nationalgrid

Amy G. Rabinowitz
Assistant General Counsel

May 3, 2006

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

RE: D.T.E. 04-116

Dear Secretary Cottrell:

On behalf of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid, I am enclosing our response to the Department's First Set of Information Requests to Massachusetts Electric Company.

Thank you for your time and attention to this matter.

Very truly yours,

Amy G Rabinowitz

Amy G. Rabinowitz

cc: Service List

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Information Request DTE-MECo 1-1

Request:

Refer to the Company's response to DTE-LDC 7-1, at 4 ("7-1") and the Company's response to RR-DTE-3, Figure 2, ("RR-3"). Please provide all data, formulas, working papers, and calculations to answer these responses.

Response:

Please refer to the following Excel files provided in the electronic filing of this response:

- "DTE 1-1a.xls" for the IEEE 1366-2003 Major Event Day calculations for Massachusetts Electric Company
- "DTE 1-1b.xls" for the IEEE 1366-2003 Major Event Day calculations for Nantucket Electric Company
- "DTE 1-1c.xls" for the penalty/offset trigger calculations for Massachusetts Electric Company

Prepared by or under the supervision of: Cheryl A. Warren

Information Request DTE-MECo 1-2

Request:

Refer to RR-3 and 7-1. In RR-3, the Company's graph shows that under IEEE 1366-2003, MECo would have paid no penalty for 2001 or 2002. In 7-1, the Company indicates that under IEEE 1366-2003, it would have paid penalties for both years. Please explain the discrepancy between RR-3 and 7-1.

Response:

In the Company's response to RR-3, the Company calculated the SAIDI targets that would have been applicable to the Company if IEEE 1366-2003 (IEEE) had been initially used during 2006, and graphed these targets in Figure 2. The target bands were based on the Company's IEEE performance for the years 1997-2005. Figure 2 also included the Company's SAIDI performance under IEEE for each of those nine years for comparison purposes. Figure 2 was not intended to depict the penalties that would have been incurred for each of the years included in the graph.

In the Company's response to 7-1, the Company calculated the SAIDI and SAIFI targets that would have been applicable to the Company for each year from 2002 through 2005 if IEEE had been used during that time. For example, the target bands for 2002 were based on the Company's IEEE performance for the years 1997-2001; the target bands for 2003 were based on the Company's IEEE performance for the years 1997-2002; and so on. The bottom graph on page 5 of 7-1 depicts the target bands for SAIFI, and the graph on page 7 depicts the target bands for SAIDI. In both of these graphs, the Company's performance under IEEE for the years 1997-2005 was also included. These graphs were intended to depict the approximate penalties that would have been incurred for each of the years from 2002 to 2005 if IEEE had been used during that time. The penalties are also summarized in the table on page 4 of 7-1.

Prepared by or under the supervision of: Cheryl A. Warren

Information Request DTE-MECo 1-3

Request:

Please identify each and every state, commonwealth, or federal district that has adopted IEEE 1366-2003 exactly as proposed in D.T.E. 04-116 as a standard for all electric distribution companies within its jurisdiction. (Do not include any state, commonwealth, or federal district where IEEE 1366-2003 was adopted for one, two or a few companies but not for all.) For each listing, state whether IEEE 1366-2003 was adopted for penalty or reporting purposes. For each state, commonwealth, and federal district, identified, provide copies of the enabling legislation, Order, or regulation adopting IEEE 1366-2003.

Response:

The Company is not aware of any state that has adopted the IEEE Std. 1366-2003 exactly as proposed in D.T.E. 04-116 as a standard for all electric distribution companies within its jurisdiction. IEEE Std. 1366-2003 was issued in June 2004. Before it can be adopted in a state, a docket must be opened. Several states have adopted IEEE Std. 1366-2003 for individual companies and are considering adopting it for all companies as their dockets open. The Company also has additional information on states that have adopted IEEE 1366-2003 in part or for some companies. Should the Department require this additional information, the Company will be happy to provide it.

Prepared by or under the supervision of: Cheryl A. Warren

Information Request DTE-MECo 1-4

Request:

Please identify each and every state, commonwealth, or federal district that has adopted IEEE 1366-2003 in some form for penalty purposes for all electric distribution companies within its jurisdiction. (Do not include any state, commonwealth, or federal district that has adopted a variation or part of IEEE 1366-2003 for one, two, or a few, companies but not for all.) Explain the difference between what was adopted in these states, commonwealths, or federal district and what is proposed in this docket. For each and every state, commonwealth, and federal district, identified, provide copies of the enabling legislation, Order, or regulation adopting IEEE 1366-2003.

Response:

The Company is aware of one state, Delaware, which has adopted IEEE Std. 1366-2003 in some form for penalty purposes for all electric distribution companies within its jurisdiction. The supporting documentation can be found in attached PSC Order No. 6745.

In Rhode Island, there is only one investor-owned electric company in the state. This company reports to the Rhode Island Public Utilities Commission (RIPUC) its annual reliability values calculated under the IEEE Std. 1366-2003 methodology for informational purposes only. Penalty calculations are based on a different set of rules. However, this company has the right to petition the RIPUC for full adoption of IEEE Std. 1366-2003 in 2007 including for penalty calculations. The RIPUC order is attached.

British Columbia used IEEE Std. 1366-2003 to waive a penalty for BC Hydro. It is considering adoption of the standard for all utilities in 2006.

Prepared by or under the supervision of: Cheryl A. Warren

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF DELAWARE

IN THE MATTER OF THE CONSIDERATION OF RULES, STANDARDS, AND INDICES TO ENSURE RELIABLE ELECTRICAL SERVICE BY ELECTRIC DISTRIBUTION COMPANIES (OPENED SEPTEMBER 26, 2000; REOPENED OCTOBER 11, 2005)	)	PSC REGULATION DOCKET NO. 50

ORDER NO. 6745

AND NOW, this 11th day of October, A.D., 2005;

WHEREAS, in PSC Order No. 6298 (Nov. 4, 2003), the Commission adopted the Electric Service Reliability Quality Regulation, which included interim benchmark standards and directed in that Order that Staff develop and propose a final regulation for implementation by January 2006;

AND WHEREAS, in compliance with that Order, on November 19, 2004, Staff published a Notice of Intent to establish a final regulation and scheduled several workshops to discuss reliability issues, which were held between December 2004 and April 2005;

AND WHEREAS, as a result of those workshops and after consideration of all input from the various interested parties, Staff revised the draft regulation and forwarded it to all interested parties for informal review and comment;

AND WHEREAS, upon review of the comments of the interested parties and after further meetings with both of Delaware's electric distribution companies, Delmarva Power & Light Company and Delaware Electric Cooperative, Inc., Staff produced a final revised draft of the regulation for consideration by the Commission, a copy of which is attached hereto as Exhibit "A;"

AND WHEREAS, it appears that there are differences of opinion on the proposed content of the revised draft regulation and the positions of various parties disagree with Staff's proposed changes, making it unlikely that a settlement will be forthcoming on some of the key elements of the draft regulation;

AND WHEREAS, the Commission believes that the proposed revised regulation should be published in the *Delaware Register of Regulations* providing public notice of the revised rulemaking to develop a final regulation and appoint a Hearing Examiner to oversee the effort.

Now, therefore, **IT IS ORDERED**:

1. That the Secretary is directed to send this Order along with the proposed revised regulation to the Delaware Register of Regulations for publication in the next issue of the *Delaware Register of Regulations*.

2. That Ruth A. Price is designated as Hearing Examiner in this matter pursuant to the terms and provisions of 26 *Del. C.* § 502 and 29 *Del. C.* ch. 101 with the authority to receive all written comments and/or testimony, briefs, or other written materials concerning the proposed rules submitted by the Commission Staff and shall organize, classify, summarize, and make recommendations with respect to such materials and proposed rules and regulations. In addition, the Hearing Examiner may conduct such public hearings, including evidentiary hearings, upon due public notice as she deems required or advisable concerning the proposed rules and regulations.

3. That James McC. Geddes, Esquire, continues as Rate Counsel in this matter and participants are notified that the cost of this proceeding will be assessed under the provisions of 26 *Del. C.* § 114(b)(1) and 26 *Del. C.* § 1012(c)(2).

4. That the Commission reserves the jurisdiction and authority to enter such further Orders in this matter as may be deemed necessary or proper.

BY ORDER OF THE COMMISSION:

/s/ Arnetta McRae
Chair

Vice Chair

/s/ Joann T. Conaway
Commissioner

/s/ Jaymes B. Lester
Commissioner

/s/ Dallas Winslow
Commissioner

ATTEST:

/s/ Norma J. Sherwood
Acting Secretary

E X H I B I T "A"

STATE OF DELAWARE
Delaware Public Service Commission

Electric Service Reliability and Quality Standards

JANUARY 2006

Contents

A. Purpose and Scope

1) Reliable electric service is of great importance to the Delaware Public Service Commission ("Commission"), because it is an essential service to the citizens of Delaware. This regulation, in support of 26 Del. C., § 1002, sets forth reliability standards and reporting requirements needed to assure the continued reliability and quality of electric service being delivered to Delaware customers and is applicable to all Delaware Electric Distribution Companies ("EDCs") and Delaware Generation Companies.

2) Nothing in this regulation relieves any utility or generation company from compliance with any requirement set forth under any other regulation, statute or order. This regulation is in addition to those required under PSC Docket No. 58, Order No. 103, Regulations Governing Service Supplied by Electrical Utilities.

3) Compliance with this regulation is a minimum standard. Compliance does not create a presumption of safe, adequate and proper service. Each EDC needs to exercise their professional judgment based on their systems and service territories. Nothing in this regulation relieves any utility from the requirement to furnish safe, adequate and proper service and to keep and maintain its property and equipment in such condition as to enable it to do so. (26 Del. C., § 209)

4) Each EDC shall maintain the reliability of its distribution services and shall implement procedures to require all electric suppliers to deliver energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligations to its customers. (26 Del. C., § 1008)

5) Each generation company operating in the state is required to provide the Commission with an annual assessment of their electric supply reliability as specified in Section J.

6) This regulation requires the maintenance and retention of reliability data and the reporting of reliability objectives, planned actions and projects, programs, load studies and actual resulting performance on an annual basis, including major events as specified in section K.

7) EDCs are responsible for maintaining the reliability of electric service to all their customers in the state of Delaware. Pursuant to this requirement, EDCs may be subject to penalties as described in Section M or 26 Del. C., §1019.

8) EDCs are required to explore the use of proven state of the art technology, to provide cost effective electric service reliability improvements.

B. Definitions

The following words and terms, as used in these regulations, shall have the following meanings, unless the context clearly indicates otherwise:

"Acceptable reliability level" is defined as the maximum acceptable limit of the System Average Interruption Frequency Index ("SAIFI"), the Customer Average Interruption Duration Index ("CAIDI") and the Constrained Hours of Operation as specified in Section D.

"ALM" means Active Load Management in accordance with Article 1, Schedule 5.2 of PJM's Reliability Assurance Agreement (RAA).

"Availability" means the measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service.

"Beginning restoration" includes the essential or required analysis of an interruption, the dispatching of an individual or crew to an affected area, and their arrival at the work site to begin the restoration process (normally inclusive of dispatch and response times).

"Benchmark" means the standard service measure of SAIFI, CAIDI and Constrained Hours of Operation as set forth in this regulation.

"Capacity" means the rated continuous load-carrying ability, expressed in megawatts ("MW") or megavolt-amperes ("MVA") of generation, transmission, or other electrical equipment.

"Capacity Emergency Transfer Objective ('CETO')" means the amount of megawatt capacity that an area or sub area must be able to import during localized capacity emergency conditions such that the probability of loss of load due to insufficient tie capability is not greater than one day in 10 years.

"Capacity Emergency Transfer Limit ('CETL')" means the amount of megawatts that can actually be imported into the area or sub area during localized capacity emergency conditions.

"Constrained hours of operation" means the hours of electric system operation during which time there are limits, transfer constraints or contingencies on the PJM DPL Zone delivery system that require off-cost dispatch of generating facilities. Total constrained hours exclude offcost operations attributable to generation or transmission forced outages, generation or transmission construction or any unrelated third party actions.

"Contingency" means the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A contingency may also include multiple components, which are related by situations leading to simultaneous component outages.

"Corrective action" means the maintenance, repair, or replacement of an EDC's utility system components and structures to allow them to function at an acceptable level of reliability.

"Corrective maintenance" means the unplanned maintenance work required to restore delivery facilities to a normal operating condition that allows them to function at an acceptable level of reliability.

"Customer Average Interruption Duration Index ('CAIDI')" represents the average time in minutes required to restore service to those customers that experienced sustained interruptions during the reporting period. CAIDI is defined as follows:

$$\text{CAIDI} = \frac{\text{Sum of all Sustained Customer Interruption Durations per Reporting Period}}{\text{Total Number of Sustained Customer Interruptions per Reporting Period}}$$

"Customers Experiencing Long Interruption Durationss ('CELIDs')" represents the total number of customers that have experienced a cumulative total of more than eight hours of outages.

"Customers Experiencing Multiple Interruptionss ('CEMIs')" is an index that represents the total number of customers that have experienced nine or more interruptions in a single year reporting period.

$$\text{CEMI}_8 = \frac{\text{Total number of customers that experienced more than eight (8) sustained interruptions}}{\text{Total number of customers served}}$$

"Delivery Facilities" means the EDC's physical plant used to provide electric energy to Delaware retail customers, normally inclusive of distribution and transmission facilities.

"Dispatch time" is the elapsed time between receipt of a customer call and the dispatch of a service resource to address the customer's issue as tracked by an Outage Management System.

"Distribution feeder" or "feeder" means a three-phase set of conductors emanating from a substation circuit breaker serving customers in a defined local distribution area. This includes three-phase, two-phase and single-phase branches that are normally isolated at all endpoints.

"Distribution facilities" means electric facilities located in Delaware that are owned by a public utility that operate at voltages of 34,500 volts or below and that are used to deliver electricity to customers, up through and including the point of physical connection with electric facilities owned by the customer.

"Electric Distribution Company" or "EDC" means a public utility owning and/or operating transmission and/or distribution facilities in this state.

"Electric distribution system" means that portion of an electric system, that delivers electric energy from transformation points on the transmission system to points of connection at the customers' premises.

"Electric service" means the supply, transmission, and distribution of electric energy as provided by an electric distribution company.

"Electric Supplier" means a person or entity certified by the Commission that sells electricity to retail electric customers utilizing the transmission and/or distribution facilities of a nonaffiliated electric utility, as further specified in 26 Del.C., §1001.

"Forced outage" means the removal from service availability of a generating unit, transmission line, or other facility for emergency reasons or a condition in which the equipment is unavailable due to unanticipated failure.[1]

"Forced outage rate" means the hours a generating unit, transmission line, or other facility is removed from service, divided by the sum of the hours it is removed from service plus the total number of hours the facility was connected to the electricity system expressed as a percent.[2]

> Multiple momentary forced outages on the same transmission line in the span of a single minute shall be treated as a single forced outage with the duration of one minute. When the operation of a transmission circuit is restored following a forced outage and the transmission line remains operational for a period exceeding one minute or more, followed by another forced outage, then these should be counted as two forced outages. Multiple forced outages occurring as a result of a single event should be handled as multiple forced outages only if subsequent operation of the transmission line between events exceeds one minute. Otherwise they shall be considered one continuous forced outage.[3]

"Generation company" means a private or publicly owned company that owns or leases, with right of ownership, plant, equipment and facilities in the state of Delaware, rated in excess of 25 MVA and capable of supplying electric energy to the transmission and/or distribution system.

"Interruption" means the loss of electric service to one or more customers. It is the result of one or more component outages, depending on system configuration or other events. See "outage" and "major event." The types of interruption include momentary event, sustained and scheduled.

"Interruption, duration" means the period (measured in minutes) from the initiation of an interruption of electric service to a customer until such service has been restored to that customer. An interruption may require step restoration tracking to provide reliable index calculations.

"Interruption, momentary event" means an interruption of electric service to one or more customers, of which the duration is less than or equal to 5 minutes. This definition includes all reclosing operations, which occur within five minutes of the first interruption. For example, if a recloser or breaker operates two, three, or four times and then holds within five minutes, the event shall be considered one momentary event interruption.

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[1] North American Electric Reliability Council – "Glossary of Terms", August 1996

[2] North American Electric Reliability Council – "Glossary of Terms", August 1996

[3] Draft CAISO Transmission Control Agreement, Appendix C, ISO Maintenance Standards

"Interruption, scheduled" means an interruption of electric service that results when one or more components are deliberately taken out of service at a selected time, usually for the purposes of preventative maintenance, repair or construction. Scheduled interruptions, where attempts have been made to notify customers in advance, shall not be included in SAIFI, CAIDI, or Forced Outage measures.

"Interruption, sustained" means an interruption of electric service to one or more customers that is not classified as a momentary event interruption and which is longer than five minutes in duration.

"Interrupting device" means a device, capable of being reclosed, whose purpose includes interrupting fault currents, isolating faulted components, disconnecting loads and restoring service. These devices can be manual, automatic, or motor operated. Examples include transmission and distribution breakers, line reclosers, motor operated switches, fuses or other devices.

"Major Event" means an event consistent with the I.E.E.E.1366, Guide For Electric Power Distribution Reliability Indices standard as approved and as may be revised. For purposes of this regulation, changes shall be considered to be in effect beginning January 1 of the first calendar year after the changed standard is adopted by the I.E.E.E. Major event interruptions shall be excluded from the EDC's SAIFI, CAIDI and Constrained Hours measurements for comparison to reliability benchmarks. Interruption data for major events shall be collected, and reported according to the reporting requirements outlined in Section K.

"Mid Atlantic Area Council ('MAAC') or Reliability First Corporation "means a regional council of the North American Electric Reliability Council ("NERC"), or successor organization, that is responsible for Mid Atlantic operational policies and reliability planning standards applicable to PJM and local electric distribution company members.

"North American Electric Reliability Council ('NERC')" means the national organization responsible for operational policies and reliability planning standards applicable to national system operations and electric distribution companies, or their successor organizations.

"Outage" means the state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption of electric service to customers, depending on system configuration.

"Outage Management System ('OMS')" means a software operating system that provides database information to effectively manage service interruptions and minimize customer outage times.

"Pre-restructuring" refers to the five-year time frame prior to Delaware's adoption of 26 Del. C., Chapter 10, Electric Utility Restructuring Statute (1995-1999).

"PJM Interconnection, L.L.C. ('PJM')" means the Regional Transmission Organization or successor organization that is responsible for wholesale energy markets and the interstate transmission of energy throughout a multi-state operating area that includes Delaware.

"Power quality" means the characteristics of electric power received by the customer, with the exception of sustained interruptions and momentary event interruptions. Characteristics of electric power that detract from its quality include waveform irregularities and voltage variations—either prolonged or transient. Power quality problems shall include, but are not limited to, disturbances such as high or low voltage, voltage spikes or transients, flicker and voltage sags, surges and short-time overvoltages, as well as harmonics and noise.

"Preventive maintenance" means the planned maintenance, usually performed to preclude forced or unplanned outages, and which allows delivery facilities to continue functioning at an acceptable level of reliability.

"Reliability" means the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system – Adequacy and Security.

> Adequacy - The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
>
> Security - The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.[4]

As applied to distribution facilities, reliability is further described as the degree to which safe, proper and adequate electric service is supplied to customers without interruption.

"Repair time" is the elapsed time from the arrival of the service resource at the identified problem site to the correction of the customer's original concern as tracked by the OMS.

"Response time" is the elapsed time from dispatch of service resource to the arrival of the service resource at the identified problem site as tracked by the OMS.

"Step restoration" means the restoration of service to blocks of customers in an area until the entire area or circuit is restored.

"Sum of all Sustained Customer Interruption Durations" means the summation of the restoration time (in minutes) for each event times the number of interrupted customers for each step restoration of each interruption event during the reporting period.

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[4]NERC definition - NERC's Reliability Assessment 2001–2010, dated October 16, 2001.

"Supervisory Control And Data Acquisition ('SCADA')" is an electronic communication and control system that provides electrical system operating information and mechanisms to remotely control energy flows and equipment.

"System Average Interruption Frequency Index ('SAIFI')" represents the average frequency of sustained interruptions per customer during the reporting period. SAIFI is defined as:

$$\text{SAIFI} = \frac{\text{Total Number of Sustained Customer Interruptions per Reporting Period}}{\text{Total Number of Customers Served per Reporting Period}}$$

"Total Number of Sustained Customer Interruptions" means the sum of the number of interrupted customers for each interruption event during the reporting period. Customers who experienced multiple interruptions during the reporting period are counted for each interruption event the customer experienced during the reporting period.

"Total Number of Customers Served" means the number of customers provided with electric service by the distribution facility for which a reliability index is being calculated on the last day of the time period for which the reliability index is being calculated. This number should exclude all street lighting (dusk-to-dawn lighting, municipal street lighting, traffic lights) and sales to other electric utilities.

"Transmission facilities" means electric facilities located in Delaware and owned by a public utility that operate at voltages above 34,500 volts and that are used to transmit and deliver electricity to customers (including any customers taking electric service under interruptible rate schedules as of December 31, 1998) up through and including the point of physical connection with electric facilities owned by the customer.

C. Electric Service Reliability and Quality

1) Each EDC shall provide reliable electric service that is consistent with pre-restructuring service levels as identified in Section D. and complies with 26 Del. C., § 1002.

2) Each EDC shall install, operate, and maintain its delivery facilities in conformity with the requirements of the National Electrical Safety Code and the operating policies and standards of NERC, MAAC and PJM, or their successor organizations.

3) Each EDC shall have targeted objectives, programs and/or procedures and forecast load studies, designed to help maintain the acceptable reliability level for its delivery facilities and, where appropriate, to improve performance.

4) Each EDC, in accordance with Section I., shall submit to the Commission, on or before March 31 of each year, a Planning and Studies Report identifying its current year's annual objectives, planned actions and projects, programs, and forecast studies that serve to maintain reliability and quality of service at an acceptable reliability level.

5) Each EDC, in accordance with Section J., shall submit to the Commission, on or before April 30 of each year, a Performance Report that assesses the achievement of the previous year's objectives, planned actions, projects and programs, and assesses the relative accuracy of forecast studies and previous years performance measures with respect to benchmarks.

6) Each generation company in accordance with Section J. shall submit to the Commission on or before April 30 of each year, a Performance Report that evaluates their reliability of energy supply.

7) Each EDC shall ensure that distribution system generation interconnection requirements are consistent with the I.E.E.E. 1547 series, "Standard for Interconnecting Distributed Resources with Electric Power Systems, as currently approved and as may be revised.

8) Each EDC shall file and maintain with the Commission a copy of the technical requirements for distribution system generation interconnection.

D. Reliability and Quality Performance Benchmarks

1) The measurement of reliability and quality performance shall be based on annual SAIFI, CAIDI and Constrained Hours of Operation measures for each EDC. SAIFI and CAIDI calculations shall include all Delaware customer outages, excluding major events, and shall be reported by its distribution, substation and transmission components. The Constrained Hours of Operations shall be based on peninsula (DPL Zone) transmission system contingency limitations that require the dispatch of off-cost generation, excluding generation or transmission forced outages, generation or transmission construction or any unrelated third party actions.

2) Each EDC shall maintain their electric service reliability and quality performance measures within the benchmark standard of this Section D., paragraph 3). SAIFI, CAIDI and Constrained Hours of Operation performance shall be measured each calendar year. Annual SAIFI, CAIDI and Hours of Constrained Operation performance equal to or better than the acceptable reliability level meets the standard of this regulation. When performance does not meet the acceptable reliability level, further review and analysis are required. The EDC may be subject to penalties as defined in Section M and subsequent corrective actions may be required.

3) For the EDCs, the electric service reliability and quality performance benchmarks are established as follows:

a) The system SAIFI benchmark standard, which is based on pre-restructuring levels of performance and adjusted to reflect a 1.75 standard deviation of data variability and the transition to an OMS system shall be as follows:
   i) Delaware Electric Cooperative SAIFI shall be 3.9 interruptions; and
   ii) Delmarva Power SAIFI shall be 1.9 interruptions.
b) The system CAIDI benchmark, which is based on pre-restructuring levels of performance and adjusted to reflect a 1.75 standard deviation of data variability and the transition to an OMS system shall be as follows:
   i) Delaware Electric Cooperative CAIDI shall be 192 minutes; and
   ii) Delmarva Power CAIDI shall be 157 minutes.
c) Based on the PEPCO/Conectiv merger settlement, the Constrained Hours of Operation benchmark standard shall be 600 hours for each EDC.

4) Each EDC shall track and report its annual performance and three-year average performance against benchmark standards in accordance with Section J.

5) Each EDC shall track and report its annual $CEMI_8$ and $CELID_8$ performance in accordance with Section J.

E. Reliability and Quality Performance Objectives

1) Each EDC shall establish electric service reliability and quality performance objectives for the forthcoming year. Objectives shall include:

a. Anticipated performance measures designed to maintain reliable electric distribution service with a description of any planned actions to achieve target objectives;
b. Anticipated performance measures designed to maintain transmission circuits and power transformers with a description of any planned actions to achieve target objectives; and
c. Annual corrective, preventive and total maintenance program hours and costs anticipated on Delaware transmission circuits, distribution circuits and substation equipment.

2) Performance objective measures shall be established to support the maintenance of electric reliability performance. Performance objectives shall be representative of expected performance, taking into consideration anticipated new construction projects, power quality and maintenance programs, planned actions and any resource or time limitations.

F. Power Quality Program

1) Each EDC shall maintain a power quality program with clearly stated objectives and procedures designed to respond promptly to customer reports of power quality concerns.

2) Each EDC shall consider power quality concerns in the design, construction and maintenance of its transmission and distribution power delivery system components to mitigate, using reasonable measures, power quality disturbances that adversely affect customers' equipment.

3) Each EDC shall maintain records of customer power quality concerns and EDC response. These records shall be made available to the Commission Staff upon request with 30 days notice.

G. Inspection and Maintenance Program

1) Each EDC shall have an inspection and maintenance program designed to maintain delivery facilities performance at an acceptable reliability level. The program shall be based on industry codes, national electric industry practices, manufacturer's recommendations, sound engineering judgment and past experience.

2) As a maintenance minimum, each EDC shall inspect and maintain as necessary its power transformers, circuit breakers, substation capacitor banks, automatic 3-phase circuit switches and all 600 amp or larger manually operated, gang transmission circuit tie switches at least once every two (2) years.

3) As a maintenance minimum, each EDC shall inspect all right-of-way vegetation at least once every four (4) years and trim or maintain as necessary. Vegetation management practices should be applied at least once every four (4) years except where growth or other assessments deem it unnecessary.

4) Each EDC shall maintain records of inspection and maintenance activities. These records shall be made available to Commission Staff upon request with 30 days notice.

H. Delivery Facility Studies

1) Each EDC shall perform system load studies to identify and examine potential distribution circuit overloads, distribution substation and distribution substation supply circuit single contingencies and all transmission system single and double contingencies as specified by NERC, MAAC, Reliability First Corp. and PJM or successor requirements. Double contingency analysis should include supply service contingencies that may cause overloads or outages on the EDC's system. Where NERC, MAAC, Reliability First Corp or PJM requirements are not applicable, the EDC shall at a minimum examine circuit and equipment overloads under normal and single contingency conditions at peak load, with and without ALM or other demand response mechanisms. The EDC shall identify all projects and/or corrective actions that are planned to mitigate reliability loading issues identified in the study.

2) Delivery facility planning studies will be performed annually under conditions specified by NERC, MAAC, Reliability First Corp. and PJM or their successor organization's planning requirements, or as specified in H., 1). Studies shall identify required projects and/or planned corrective actions. For any study resulting in a thermal overload or an out-of-range voltage level, the study shall be performed again after the implementation of Active Load Management (ALM), system switching or reconfiguration.

3) Each EDC shall perform the electric delivery facility system planning studies as described herein in the fall of each year (year a) for the upcoming summer period (year b) and for the summer period two years later (year c). The planning studies will include all delivery facility enhancements planned to be in-service during the applicable summer peak and shall identify those delivery facilities that are anticipated to be overloaded during the peak demand period.

I. Planning and Studies Report

1) Prior to March 31 of each year, each EDC shall convene a stakeholder meeting offering opportunity for interested parties to discuss electric service reliability or quality concerns within Delaware. Such meeting shall be limited to discussion of publicly available information and at a minimum be open to generation companies, electric suppliers, municipals or other EDCs, PJM, state agencies and wholesale/retail consumers. Each EDC shall consider the resulting issues and include mitigation efforts in annual plans as appropriate.

2) By March 31 of each year, each EDC shall submit a reliability planning and studies report to the Commission for review. The report will identify current reliability objectives, load study results and planned actions, projects or programs designed to maintain the electric service reliability and quality of the delivery facilities.

3) The report shall include the following information:

a. Objective targets or goals in support of reliable electric service and descriptions of planned actions to achieve the objectives;
b. Delivery load study results as described in Section H, to include at a minimum the information for both year b and year c as specified in Section H, paragraph 3);
c. Description and estimated cost of capital projects planned to mitigate loading or contingent conditions identified in load studies or required to manage hours of congestion;
d. The EDC's power quality program and any amendments as required in Section F;
e. The EDC's inspection and maintenance program, any amendments as required in Section G., and any specific actions aimed at reducing outage causes;
f. Copies of all recent delivery facility planning studies and network capability studies (including CETO and CETL results) performed for any delivery facilities owned by the utility; and
g. Summaries of any changes to reliability related requirements, standards and procedures at PJM, MAAC, First Reliability Corporation, NERC or the EDC.

h. Summary of any issues that resulted from the EDC stakeholder meeting and any projects or planning changes that may have been incorporated as a result of such meeting.

J. Annual Performance Report

1) By April 30 of each year, each EDC shall submit an annual Performance Report, summarizing the actual electric service reliability results. The report shall include the EDC's average three-year performance results, actual year-end performance measure results and an assessment of the results/effectiveness of the reliability objectives, planned actions and projects, programs, and load studies in achieving an acceptable reliability level.

2) Delivery facilities year-end performance measures, as established in section D., paragraph 1), shall be reported as follows:

   a. SAIFI, and CAIDI measures:
      i) Current year and three-year average reflecting Delaware performance, classified by distribution, substation and transmission components; and
      ii) Current year for each feeder circuit providing service to Delaware customers, regardless of state origin.

   b. Constrained hours of operation:
      i) Current year and three-year average for the EDC's DPL Zone transmission system; and
      ii) Current year for the EDC's DPL Zone, classified by cause.

3) The Performance Report shall identify 2% of distribution feeders or 10 feeders, whichever is more, serving at least one Delaware customer, that are identified by the utility as having the poorest reliability. The EDC shall identify the method used to determine the feeders with poorest reliability and shall indicate any planned corrective actions to improve feeder performance and target dates for completion or explain why no action is required. The EDC shall ensure that feeders, identified as having the poorest reliability, shall not appear in any two consecutive Performance Reports without initiated corrective action.

4) The Performance Report shall include annual information that provides the Commission with the ability to assess the EDC's efforts to maintain reliable electric service to all customers in the state of Delaware. Such reporting shall include the following items:

   a. Current year expenditures, labor resource hours, and progress measures for each capital and/or maintenance program designed to support the maintenance of reliable electric service, to include:
      i. Transmission vegetation maintenance;
      ii. Transmission maintenance, excluding vegetation, by total, preventive, and corrective categories;
      iii. Transmission capital infrastructure improvements;
      iv. Distribution vegetation maintenance;
      v. Distribution maintenance, excluding vegetation, by total, preventive and corrective categories;
      vi. Distribution capital infrastructure improvements;
      vii. Transmission and Distribution progress per Section G., 2) & 3); and
      viii. Any related process, practice or material improvements.

b. Current year OMS data to include:
    i. Number of outages by outage type;
    ii. Number of outages by outage cause;
    iii. Total number of customers at year end;
    iv. Total number of customers that experienced an outage; and
    v. Total customer minutes of outage time.
c. Current year $CELID_8$ and $CEMI_8$ results, exclusive of major events, including any efforts being made to reduce the occurrences of multiple outages or long duration outages.
d. Current year customer satisfaction or other measures the EDC believes are indicative of reliability performance.

5) The Performance Report shall include a summary of each major event for which data was excluded, and an assessment of the measurable impact on reported performance measures.

6) In the event that an EDC's reliability performance measure does not meet an acceptable reliability level for the calendar year, the Performance Report shall include the following:

    a. For not meeting SAIFI, an analysis of the customer service interruption causes for all delivery facilities that significantly contributed to not meeting the benchmark;
    b. For not meeting CAIDI, an analysis of the duration of service interruptions for all delivery facilities by dispatch, response and repair times that significantly contributed to not meeting the benchmark;
    c. For not meeting Constrained Hours of Operation, an analysis of significant constraints by cause;
    d. A description of any corrective actions that are planned by the EDC and the target dates by which the corrective action shall be completed; and
    e. If no corrective actions are planned, an explanation shall be provided.

7) The Performance Report shall include copies of current procedures identifying methods the EDC uses to ensure the electric supplier delivery of energy to the EDC at locations and in amounts which are adequate to meet each electric supplier's obligation to its customers.

8) The Performance Report shall include certification by an officer of the EDC of the data and analysis and that necessary projects, maintenance programs and other actions are being performed and adequately funded by the Company as addressed in its annual plans.

9) By April 30 of each year, each generation company shall submit an annual Reliability Performance Report. The performance report shall include the individual unit and average station forced outage rates and any anticipated changes that may impact the future adequacy of supply. Each generation company shall also provide the Commission with at least a one-year advanced notification of any planned unit retirements, planned re-powerings or planned long-term unit de-ratings.

K. Major Event Report

1) Each EDC shall notify the Commission of major events as soon as practical, but not more than 36 hours after the onset of a major event. Initial notification is required when more than 10% of an EDC's customers experience a sustained outage during a 24 hour period; however, I.E.E.E. 1366 standard shall apply to all performance calculations.

2) Each EDC is expected to restore 95% of all customers experiencing a major event within three (3) days and 100% within five (5) days. Performance not meeting this level will require further review, analysis and explanation. The EDC may be subject to subsequent corrective actions and penalties as permitted by 26 Del. C. § 1019.

3) The EDC shall, within 15 business days after the end of a major event, submit a written report to the Commission, which shall include the following:

   a. The date and time when the EDC's major event control center opened and closed;
   b. The total number of customers out-of-service over the course of the major event in six hour increments;
   c. The date and time when 95% of customers and the last customer affected by a major event was restored;
   d. The total number of trouble assignments repaired, by facility classification (poles, miles of wire, transformers);
   e. The time at which the mutual aid and non-company contractor crews were requested, arrived for duty and were released, and the mutual aid and non-contractor response(s) to the request(s) for assistance; and
   f. A timeline profile in six-hour increments of the number of company line crews, mutual aid crews, non-company contractor line and tree crews working on restoration activities during the duration of the major event, summarized by total number of line, bucket, trouble, and tree types.

L. Prompt Restoration of Outages

1) Each EDC shall strive to restore service as quickly and as safely as possible at all times EDCs shall begin the restoration of service to an affected service area within two hours of notification by two or more customers of any loss of electric service. In situations where it is not practical to respond within two hours to a reported interruption (safety reasons, inaccessibility, multiple simultaneous interruptions, storms or other system emergencies), the EDC shall respond as soon as the situation permits.

2) Each EDC shall monitor dispatch, response and repair times for customer outages. In the event that average annual dispatch, response or repair performance times exceed the EDC's expected levels for the calendar year, the EDC shall include the following in its annual performance report.

   a. An analysis of the factors which caused the unexpected performance; and
   b. A description of any corrective actions planned by the EDC to meet expected performance levels.

3) Each EDC shall have outage response procedures that place the highest priority on responding to emergency situations for which prompt restoration is essential to public safety. These procedures should include recognition of priority requests that may come from police, fire, rescue, authorized emergency service providers or public facility operators.

M. **<u>Penalties and Other Remedies</u>**

1) Private or investor owned utilities and cooperatives, operating in Delaware under the regulation of the Commission, are subject to penalties and other remedial actions in accordance with 26 Del.C., § 205(a), § 217, and § 1019. The Commission shall be responsible for assessing any penalty under this section, consistent with Delaware law. In determining if there should be a penalty for violation of a reporting requirement or benchmark standard and, if so, what the penalty amount should be, the Commission shall consider the nature, circumstances, extent and gravity of the violation including the degree of the EDC's culpability and history of prior violations and any good faith effort on the part of the EDC in attempting to achieve compliance. Such penalty shall not exceed $5,000 for each violation, with the overall penalty not to exceed an amount reasonable and appropriate for the violation (maximum of $600,000 per year per reporting or standard violation). Each day of noncompliance shall be treated as a separate violation. In the case of an electric cooperative, in violation of a reporting requirement or benchmark standard, the Commission shall not assess any monetary penalty that would adversely impact the financial stability of such an entity and any monetary penalty that is assessed against an electric cooperative shall not exceed $1,000 for each violation, which each day of noncompliance shall be treated as a separate violation (maximum of $60,000 per year per reporting or standard violation). Nothing in this section relieves any private or investor owned utility or cooperative from compliance or penalties, that may be assessed due to non-compliance with any requirement set forth under any other regulation, statute or order.

2) An EDC shall be considered in violation of the SAIFI, CAIDI or Constrained Hours of Operation performance benchmark standard when the annual year-end cumulative measure exceeds the benchmark standard. The term of the violation shall extend for the period of time during which the performance measure exceeded the benchmark standard, except in the case of the non-cumulative CAIDI measure, where such term of violation shall extend for the period of time after which a rolling 12 month measure exceeds the benchmark standard.

3) Upon failure of any EDC to meet performance benchmark standards, the EDC shall report monthly, or over such other period of time that the Commission shall establish by order, the latest performance indices, until such time as performance meets the acceptable reliability level.

4) Each EDC not meeting performance benchmark standards as required by Section D., shall inform its customers, in writing, of the results and plans to improve electric service reliability and quality by July 1 of the year following any year in which its performance does not meet an acceptable reliability level.

5) Each violation of any reporting rule or performance standard of this regulation shall constitute a single, separate and distinct violation for that particular day. Each day during which a violation continues shall constitute an additional, separate and distinct violation. Provided, however, that a violation of a performance measure shall not be deemed to be a violation per customer, whether affected or otherwise, but shall constitute a single Delaware-wide violation for the day.

6) Penalty assessments are payable as provided by Delaware statute.

N. Outage and Control Systems

1) Each EDC shall implement and maintain an Outage Management System (OMS) and a Supervisory Control and Data Acquisition System (SCADA) as described in this section by January 1, 2007.

2) The OMS, at a minimum, shall consist of an outage assessment software program, integrated with a geographic information system that permits an EDC to effectively manage outage events and restore customer service in a timely manner.

3) The OMS should permit the EDC to:

a. Group customers who are out of service to the most probable interrupting device that operated;
b. Associate customers with distribution facilities;
c. Generate street maps indicating EDC outage locations;
d. Improve the management of resources during a storm;
e. Improve the accuracy of identifying the number of customers without electric service;
f. Improve the ability to estimate expected restoration times;
g. Accurately identify the number and when customers were restored; and
h. Effectively support the dispatch of crews and/or service personnel.

4) The SCADA system, at a minimum, shall consist of a remote monitoring and operating ability for all major substation equipment integral to maintaining the reliability of the system. The system will have the ability to:

a. Monitor and record critical system load data and major equipment status;

b. Provide remote operational control over major equipment; and

c. Incorporate generally accepted utility industry safety and security standards.

O. Reporting Specifications and Implementation

1) Planning and Studies Reports, Performance Reports and Major Event Reports provided under this regulation are subject to annual review and audit by the Commission. Each EDC and generation company must maintain sufficient records to permit a review and confirmation of material contained in all required reports.

2) Reports shall be submitted as an original and 5 paper copies with one additional copy submitted electronically to the Secretary, Delaware Public Service Commission, with certification of authenticity by an officer of the corporation. The electronic copy may be posted on the Delaware Public Service Commission's Internet website.

3) Each EDC or generation company may request that information, required under this regulation, be classified as confidential, proprietary and/or privileged material. The requesting party must attest that such information is not subject to inspection by the public or other parties without execution of an appropriate proprietary agreement. Each party requesting such treatment of information is also obligated to file one (1) additional electronic and paper copy of the information, excluding the confidential or proprietary information. The Commission, in accordance with Rule 11, Rules of Practice and Procedure of the Delaware Public Service Commission, effective May 10, 1999, will treat such information as "confidential, not for public release" upon receipt of a properly filed request. Any dispute over the confidential treatment of information shall be resolved by the Commission, designated Presiding Officer or Hearing Examiner.

4) This regulation is effective January 1, 2006.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NARRAGANSETT ELECTRIC COMPANY :
SERVICE QUALITY PLAN : DOCKET NO. 3628

REPORT AND ORDER

In Docket No. 2930, the Rhode Island Public Utilities Commission ("Commission") approved a Service Quality Plan ("SQP") for Narragansett Electric ("Narragansett"). This SQP would remain in effect through December 31, 2004. On May 28, 2004, the Commission required Narragansett to file by August 1, 2004 a new SQP for effect January 1, 2005.

I. NARRAGANSETT'S AUGUST 2, 2004 FILING

On August 2, 2004, Narragansett filed its proposed SQP. In support of its filing, it submitted pre-filed testimonies by Robert McLaren, Cheryl Warren and Mark Sorgman. Mr. McLaren, a senior vice-president of the New England distribution companies of National Grid, summarized the SQP approved in Docket No. 2930 and the SQP being proposed by Narragansett Electric. Mr. McLaren indicated that the SQP approved in Docket No. 2930 compared Narragansett's actual annual performance in four reliability performance measures and two customer service performance measures with historical performance in these same areas. The reliability performance measures were the system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI") for both the Capital and Coastal districts. Each reliability measure had a maximum annual penalty of $500,000 and a maximum offset of $375,000. In addition, the two customer service measures were customer contact satisfaction and telephone calls answered within 20 seconds. Each customer service measure had a maximum annual penalty of $200,000 and a maximum offset of $150,000. The total maximum annual penalty was $2.4 million or approximately 1.1 percent of Narragansett's distribution revenues.[1]

The benchmarks for these service measures were based on historical performance over a period of a year. The threshold for accruing penalties for below average performance was one standard deviation worse than average performance and the threshold for accruing offsets for good performance was one standard deviation better than average performance. The penalty or offset at this threshold was scaled between the first and second standard deviation while performance that exceeded the second standard deviation would trigger either the maximum penalty or maximum offset. In addition, Mr. McLaren explained that only reliability and related offsets could be carried forward to the following year and discussed the doubling penalty provision for significant and persistent deterioration in service quality. Also, he noted that Narragansett had incurred $1,774,000 in service quality penalties by the end of 2003.[2]

Mr. McLaren discussed some of the new features in Narragansett's proposed SQP. First, all performance standards would include the four most recent years, the years 2000 through 2003. Second, the benchmarks would be updated annually based on a ten-year rolling average. Third, the calculation of reliability performance would be based on the recently adopted IEEE Standard 1366-2003. Fourth, the standard deviation for reliability standards will be based on a logarithm rather than a Gaussian "bell-shaped" curve because historical reliability performance data is asymmetrical. Fifth, the Capital and Coastal districts for reliability would be aggregated into one standard. Sixth,

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[1] Narr. Ex. 1A (McLaren's direct testimony), pp. 3-5.
[2] Id., pp. 5-8.

Narragansett proposed to include calls to the Voice Response Unit ("VRU") in calculating its telephone calls answered within 20 seconds.[3]

Mr. McLaren stated that the size of the penalty and weight of the penalties should remain unchanged from the prior service quality plan. Furthermore, Mr. McLaren argued that offsets should remain in place to give an incentive for Narragansett to strive to exceed performance benchmarks rather than just meet the benchmarks.[4]

Narragansett submitted the pre-filed testimony of Cheryl Warren, a manager of T&D Systems Engineering at National Grid. Ms. Warren stated that Narragansett currently has four reliability measures, which are SAIFI and SAIDI for the Capital and Coastal districts. Ms. Warren indicated that the Capital and Coastal districts should be combined. She noted that in 2002, Narragansett combined these two operating districts into one operational area. Ms. Warren explained that by weighting the Capital and Coastal districts by customers served in the district, which is 61% in the Capital district and 39% in the Coastal district, the performance trends of the individual districts and the weighted statewide area are similar.[5]

Ms. Warren described the IEEE Standard 1366-2003, which defines reliability enduces and terms. This new standard includes the Major Event Day ("MED") concept. The MED concept varies significantly within the industry, but should represent crisis conditions when system design and/or operational limits are exceeded. A MED is calculated by utilizing the daily SAIDI for five sequential years. Also, according to Ms. Warren, reliability data is not distributed on a normal or Gaussian "bell-shaped" curve. She stated that days with a particularly high level of minutes of interruption would

[3] Id., pp. 9-11.
[4] Id., pp. 11-15.
[5] Narr. Ex. 1B (Ms. Warren's direct testimony), pp. 1-9.

constitute a MED. Ms. Warren indicated that reliability data should be distributed in a lognormal manner. Accordingly, Ms. Warren opined that the use of the IEEE Standard 1366-2003 would give regulators and the Company a clearer understanding of Narragansett's reliability performance.[6]

Also, Ms. Warren stated that the performance benchmarks should be based on a ten-year rolling average, starting with 1994-2003. She noted that in 1999, Narragansett Electric began using an automated data collection and reporting system, Interruption Disturbance System ("IDS"), to track interruptions. According to Ms. Warren, this system change caused the reported metrics to increase by approximately 20 percent. Also, in 2000, the Eastern Utilities Associates ("EUA") merged with Narragansett and its data collection processes were converted to Narragansett's processes, which improved the accuracy of the reliability data. Also, Ms. Warren stated that using a ten-year period to establish performance benchmarks reduces the effects of the short-term variability of data.[7]

Utilizing the IEEE methodology, Ms. Warren indicated that the reliability benchmarks would have a narrower deadband for standard deviations thus tightening the thresholds at which Narragansett would incur an offset or a penalty. Also, Ms. Warren stated that utilizing the IEEE methodology would have caused Narragansett to pay a penalty for SAIDI performance from 2001 through 2003, but would not have caused Narragansett to pay a penalty for SAIFI performance during the same time period. Under the current Narragansett SQP, Narragansett paid a penalty for SAIFI performance from 2001 through 2003, and the maximum penalty for SAIDI performance in 2003 only.

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[6] Id., pp. 10-24.
[7] Id., pp. 24-26.

Furthermore, utilizing the IEEE methodology through 2003, Narragansett was in the top quartile for SAIDI and Customer Average Interruption Duration Index ("CAIDI") and in the second quartile for SAIFI for over 80 companies located throughout the United States and Canada that ranged in size from 1,400 to 5 million customers. Narragansett is considered a medium size company serving more than 100,000 customers but no more than 1 million customers. She noted that Narragansett's performance was much better than both its peers and electric utilities in other groups. Furthermore, she explained that the worsening in average SAIDI performance in medium sized companies has a similar slope to Narragansett's performance, which may be indicative of improvements in data collection, worsening weather conditions, or facility deterioration.[8]

In the pre-filed testimony of Mark Sorgman, Manager of Small Business Services for National Grid, Mr. Sorgman described Narragansett's two customer service measures in the SQP. Mr. Sorgman explained that the customer contact measure is based on a telephone survey performed by an independent research firm to contact customers who have recently contacted the company's call center to measure their satisfaction in various areas such as power outages, meter issues, and bill payments. Also, Mr. Sorgman explained that the call answering measure which is calculated by dividing the number of calls answered by customer service representatives ("CSRs") within 20 seconds by the total number of calls answered by CSRs during the year. He indicated that a call is answered when it reaches the CSR and that the time to answer is measured once the customer selects the option to speak with a CSR thus leaving the recordings of the VRU. Mr. Sorgman proposed that the benchmarks in the customer service area be based on historical performance from 1997 to 2003 with a ten-year rolling average. Also, Mr.

[8] Id., pp. 27-36.

Sorgman proposed that the call answering measure include calls completed in the VRU. He opined that some customers prefer self-service of the VRU, which is the equivalent of having a request satisfied by a CSR. Also, he noted that since 2000 Narragansett has tracked the number of VRU calls and including these calls has the effect of increasing the benchmark for the benefit of customers.[9]

II. SETTLEMENT

Subsequently, on September 28, 2004, the Commission approved a new distribution rate settlement, which made certain modifications to any new SQP for Narragansett. The modifications included: a reduction in the maximum annual service quality penalty from \$2.4 million to \$2.2 million; the elimination of penalty offsets between years and the elimination of doubling of penalties provision. After approval of a settlement requiring a rate freeze of Narragansett's distribution rates through 2009, Narragansett and the Division engaged in negotiations regarding a new SQP.

On December 29, 2004, Narragansett filed a Settlement Agreement between it and the Division of Public Utilities and Carriers ("Division").[10] The new SQP agreed to by the parties would make various changes to SQP. First, the reliability performance benchmarks would be based on the Company's performance from 1995 through 2002, and the benchmark would be calculated utilizing the natural logarithm method. Second, the current extraordinary event criteria would be used but Narragansett will annually report, for information purposes, the annual SAIDI and SAIFI results utilizing the IEEE Standard 1366-2003. Also, Narragansett could petition the Commission after two years to modify the SQP to adopt the IEEE Standard 1366-2003. Third, the calls answered

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[9] Narr. Ex. 1C (Mr. Sorgman's testimony), pp. 1-6.
[10] The Settlement is attached as Appendix A and is hereto incorporated by reference herein.

performance benchmark will be based on the company's performance from 1996 through 2004 while the customer contact survey performance benchmark would be based on the Company's performance from 1997 through 2004, and would include calls completed by the VRU. Fourth, the maximum potential offset for penalty would be 25% of the maximum penalty for that metric rather than 75% under the current SQP.

III. NARRAGANSETT'S SUPPLEMENTAL TESTIMONY

On December 29, 2004, Narragansett submitted supplemental pre-filed testimonies by Robert McLaren, Cheryl Warren, and Mark Sorgman. In his supplemental testimony, Mr. McLaren stated that the SQP's "principal objective" was "to maintain or improve the quality of service to its customers." He noted that the Rate Freeze Settlement of Docket No. 3617 addressed various SQP issues. First, the performance benchmarks would be based on the Company's historical performance. Second, the SQP would assess Narragansett's performance annually. Third, any penalty offsets can only be applied to the year in which they are earned. Fourth, the maximum penalty in each year will be set at $2.2 million or approximately 1% of Narragansett's distribution revenues. Fifth, any penalty would be credited to customers in the year they accrue. Sixth, the provision for the potential doubling of penalties in the event of significant and persistent deterioration in performance was eliminated.[11] Mr. McLaren also summarized various changes to the SQP pursuant to the Settlement. Furthermore, he clarified that although the penalty is slightly reduced, the annual penalty is weighed 83% or $1.832 million towards reliability and the remainder or $368,000 is for customer service.[12]

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[11] Narr. Ex 2A (Mr. McLaren's supplemental testimony), pp. 1-8.
[12] Id., pp. 9-18.

In her pre-filed supplemental testimony, Ms. Warren discussed the reliability measures in the SQP Settlement. Ms. Warren explained that the new performance benchmark will not include the years 1993 and 1994 because the data is less robust compared to the years in which the company utilized IDS to track interruptions. She noted that combining the Capital and Coastal districts benefits customers because the proposed performance targets at which penalties would be applied are more stringent than if the years 1993, 1994 and 2003 were included in the benchmarks.[13]

In his pre-filed supplemental testimony, Mr. Sorgman discussed the customer service benchmarks in the SQP Settlement. Mr. Sorgman explained that these benchmarks will include the results of 2004. Also, he noted that by including calls completed through VRU would make the benchmark more stringent and a make it more difficult to earn offsets in the area of call answering. He stated that Narragansett has achieved offsets in this measure since 2002.[14]

IV. DIVISION'S TESTIMONY

On December 30, 2004, the Division submitted the pre-filed testimony of Dr. John Stutz, an outside consultant. In his pre-filed testimony, Dr. Stutz discussed the new SQP proposed in the Settlement. Dr. Stutz noted that under the current SQP Narragansett has incurred $2,026,729 in penalties of which $1,024,224 was associated with reliability in 2003. Dr. Stutz noted the reduction in maximum offsets from 75 percent to 25 percent of maximum penalty, which moves the new SQP in the direction of eliminating offsets as suggested by NEGas' SQP, and reduces the likelihood that poor performance in one area will be significantly offset by good performances in another. He explained that updating

[13] Narr. Ex. 2B (Ms. Warren's supplemental testimony), pp. 1-7.
[14] Narr. Ex. 2C (Mr. Sorgman's supplemental testimony), pp. 1-5.

the customer contact performance benchmark has a negligible impact on the mean and standard deviations. Also, he stated that updating the call response performance benchmark will have a small impact on the mean but will result in a large standard deviation. However, he explained that this large standard deviation reduces the likelihood of penalties and offsets equally. Also, he noted that with the exception of 2001, Narragansett's performance in this area has been good and in fact, it is the only measure in which offsets have been greater than penalties incurred.[15] As for the reliability performance benchmarks, Dr. Stutz stated that the new measures are only slightly different from the prior measures except for a roughly 9 percent decline in the mean for SAIDI which reflects a shift in data collection technology and not service quality. In addition, Dr. Stutz explained that the use of logarithmic data allows the threshold for offsets to be closer to the mean then the threshold for penalties. To avoid the asymmetry, he noted the reduction in the offsets to 25% resolves this problem.[16]

V. HEARING

After duly published notice, the Commission conducted a public hearing on January 31, 2005 at its offices located at 89 Jefferson Boulevard, Warwick, Rhode Island. The following appearances were entered:

FOR NARRAGANSETT:	Laura Olton, Esq.
FOR THE DIVISION:	Leo Wold, Esq. Special Assistant Attorney General
FOR THE COMMISSION:	Steven` Frias, Esq. Executive Counsel

[15] Div. Ex. 1 (Dr. Stutz's testimony), pp. 1-10.
[16] Id., pp. 10-13.

The following witnesses were presented as a panel: Mr. McLaren, Ms. Warren and Mr. Sorgman for Narragansett, and Dr. Stutz for the Division. Dr. Stutz stated that the performance measures and the methodologies of the new SQP are rather standard in the electric industry. He also stated that generally the performance benchmark for an electric utility is based on the historical performance of the specific utility but at times has been based on the performance of other utilities in the region. In addition, he characterized the service quality of Narragansett as good in comparison to other electric utilities. Dr. Stutz emphasized that the new SQP is in the best interest of ratepayers because years with clearly bad performances are excluded from calculating the benchmark such as 2003 in the reliability area. Also, he stated that the new SQP makes a significant movement away from offsets. Furthermore, Dr. Stutz indicated that once the data for 2003 is excluded there is no real dramatic difference between reliability service in the capital and coastal districts.[17] In addition, Mr. McLaren stated that Narragansett will provide the Division with a reasonably prompt notice of events Narragansett deems constitutes an extraordinary event under the new SQP. Also, Ms. Warren noted that the Division has access to information from Narragansett as to how long an outage endured on a transformer-by-transformer basis. Lastly, Dr. Stutz pointed out that Narragansett reports the five percent of all circuits that are the worst performing.[18]

COMMISSION FINDINGS

The general purpose of a service quality program is to ensure that ratepayers receive a reasonable level of service. Because electric distribution service is clearly a monopoly, a service quality program is necessary to protect customers. A service quality

[17] Tr. 1/31/05, pp. 24-26, 42-46.
[18] Id., pp. 49-50, 53-56.

program for Narragansett Electric is even more necessary to ensure that merger savings are not achieved at the expense of service quality. The current SQP of Narragansett Electric is designed to maintain or improve the service quality of ratepayers in light of the cost cutting arising from the merger. As a result, under the current SQP, Narragansett Electric incurred $1,774,097 in service quality penalties during the rate freeze period of 2000 through 2004.[19] Thus, a new SQP for Narragansett Electric must likewise be designed to maintain or improve the service quality of ratepayers, and penalize Narragansett Electric for failing to do so.

In the topics of penalty amount and weighing of the penalty, the proposed SQP is nearly identical to the current SQP. The current and the proposed SQPs both weigh 83% of the penalty to the reliability service measures and the remaining 17% to the customer service measures. This approach is appropriate because reliability is of the utmost concern to all ratepayers. Without reliable electric service, a modern society, economically and socially, would decline. Thus, placing 83% of a potential penalty upon reliability service measures demonstrates the importance of reliability to the Commission. As for the penalty amount, the proposed SQP allows for $2.2 million which is approximately 1% of Narragansett Electric's distribution revenues and is very similar to the $2.4 million or 1.1% of Narragansett Electric's overall service quality during the rate freeze period of 2000 through 2004. A maximum annual penalty of $2.2 million should be a sufficient deterrent to Narragansett against declining service quality.

In the area of service measures, there are some differences between the current SQP and the proposed SQP. In the reliability service measures, the Capital and Coastal districts are being combined under the proposed SQP. This could be problematic if these

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[19] Narr. Elec.'s 5/2/05 filing in Docket No. 3617.

two districts have very different service quality results. Narragansett Electric acknowledged that the Coastal district has less load density and is more exposed to severe storms than the Capital district.[20] However, it should be noted that with the exception of 2003, during the rate freeze, the reliability data for the Coastal and Capital districts were nearly identical.[21] Overall, it appears that the two districts are generally comparable in service quality and can be combined in the new SQP so as to align the SQP measures with the operational plan of Narragansett Electric.

In the area of performance benchmark standards, it is to be expected that combining the Capital and Coastal districts will cause some changes to reliability benchmarks. However, it is imperative that clear poor service quality performance not be included in calculating and establishing any new performance benchmarks. For reliability benchmarks, the exclusion of 2003 data when Narragansett Electric incurred significant penalties is clearly appropriate. Thus, the reliability performance data used in calculating the reliability service benchmarks is limited to 1995 through 2002.[22]

When comparing the current benchmarks for SAIFI and SAIDI in the Capital and Coastal districts with the proposed benchmarks for SAIFI and SAIDI, it is apparent that the proposed SAIFI benchmark is very similar to the current SAIFI benchmarks. Unfortunately, it appears that the proposed SAIDI benchmark is approximately 9% less stringent than the current SAIDI benchmark for the Capital district. This difference is

[20] PUC Ex. 1 (Narr. Data Resp. 1-2).

[21] Id. When the 2003 data is removed the average SAIDI for the Coastal district was 70.1 while the Capital district was 72.5, and the average SAIFI for the Coastal district was 1.05 while the Capital district was 1.04.

[22] The Commission considered excluding the SAIDI performance of 2001 because Narragansett Electric incurred a significant penalty that year. However, the exclusion of the data would have changed the benchmark in a very slight manner, approximately 1 percent. Furthermore, Narragansett Electric explained that poor performance on June 11 and 12, 2001, should, in retrospect, have been classified as an extraordinary event. PUC Ex. 1 (Narr. Data Resp. 1-11).

caused by the combining of the two districts into one operational area for new service measures and the change in data collection systems related to tracking interruptions which was implemented in 1999. Most importantly, Narragansett Electric's performance in SAIDI from 2000 to 2003 has been in the top quartile compared to other electric utilities and furthermore the average SAIDI performance for medium sized companies like Narragansett Electric has declined slightly from 2000 to 2003. Based on all these considerations, it appears that the proposed SAIFI and SAIDI benchmarks are reasonable.

For customer service benchmarks, the proposed benchmark for calls answered within 20 seconds will be based on the data from 1996 to 2004 and will include calls answered by VRU. These changes in the benchmark will make it harder for Narragansett Electric to incur a penalty or an offset because the standard deviation is larger. However, during the period 2002 through 2004, Narragansett Electric has incurred offsets for this benchmark because of its inclusion of VRU data. With this large standard deviation, it will make it more challenging for Narragansett Electric to achieve an offset. Thus, the new proposed benchmark appears reasonable and reflects new technological changes in customer service. As for the customer contact benchmark, the proposed benchmark will be based on the data from 1997 to 2004. The current customer contract benchmark and the proposed benchmark are very similar and therefore the proposed benchmark can be adopted.

As for the offsets, the proposed reliability benchmarks will be calculated utilizing a logarithmic method rather than the Gaussian "bell curve" method in the current benchmarks to determine the threshold for penalties and offsets. Both Narragansett Electric and the Division have determined that reliability data is logarithmic.

Furthermore, the IEEE standard 1366-2003, which is slowly become an industry standard, recognizes the logarithmic nature of reliability data. It appears that the use of the logarithmic method is appropriate for reliability. However, a significant problem with the use of logarithmic method for benchmarks is the asymmetric nature of offsets and penalties whereby the threshold for offsets is closer to the mean than the threshold for penalties. To address this problem, the amount of the maximum offset is reduced from 75% of the maximum penalty to 25% of the maximum penalty. This reduces the asymmetry in the reliability benchmarks. Furthermore, this reduction in the maximum offset to 25% is applied to the customer service benchmarks as well. This reduction in offsets in the proposed SQP is in the best interest of ratepayers because offsets can allow a utility to ignore the poor performance in certain areas. This proposed SQP better reflects the policy objective that a utility should perform well in all areas of service.

Lastly, the IEEE has developed a standard for determining major event days, IEEE Standard 1366-2003. Although the proposed SQP does not adopt this new standard, it provides Narragansett with the opportunity to petition the Commission in 2007 to adopt it. This is appropriate because it is important for regulators to have the information necessary to determine if the use of the IEEE standard is significantly different from the currently used definition of extraordinary events and what impact if any this new standard would have on the reliability benchmarks. Furthermore, the Commission is pleased that the Division will seek more timely reporting by Narragansett Electric of the occurrence of extraordinary events.[23] This will help ensure that the reliability data is accurate. In addition, the Commission will remain vigilant and expects the Division will do so as well regarding very poor reliability performance in certain

[23] PUC Ex. 2 (Div. Data Resp. 9).

areas, which may be masked because the overall state performance is acceptable. Accordingly, at an open meeting on February 2, 2005, the Commission reviewed the evidence and approved the proposed Settlement as being in the public interest.

Accordingly, it is

(18294) ORDERED:

1. Narragansett Electric's proposed Service Quality Plan, filed on August 2, 2004, is denied.

2. The Settlement Agreement incorporating a new Service Quality Plan filed on December 29, 2004 is approved.

EFFECTIVE IN WARWICK, RHODE ISLAND ON JANUARY 1, 2005 PURSUANT TO AN OPEN MEETING ON FEBRUARY 2, 2005. WRITTEN ORDER ISSUED JULY 12, 2005.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert Holbrook, Commissioner

State of Rhode Island and Providence Plantations
Public Utilities Commission

The Narragansett Electric Company	)	R.I.P.U.C. No. 3628

Settlement Agreement

WHEREAS, under the Third Amended Stipulation and Settlement approved in Docket No. 2930 ("Docket No. 2930 Settlement"), The Narragansett Electric Company ("Narragansett" or the "Company") implemented a service quality ("SQ") plan that has been in effect since the 2000 calendar year ("2930 SQ Plan").

WHEREAS, under the terms of the Docket No. 2930 Settlement, the parties to that settlement can seek to change or terminate the 2930 SQ Plan for the period after 2004; however, if not otherwise changed, that SQ plan remains in effect beyond 2004 unless modified by the Commission.

WHEREAS, on August 2, 2004, at the direction of the Commission, Narragansett filed a proposal to amend its existing SQ plan effective January 1, 2005, and the Commission subsequently established this Docket No. 3628 to evaluate the Company's filing.

WHEREAS, in its August 2 proposal, Narragansett proposed a SQ plan that built upon the 2930 SQ Plan, but with a number of updates to better reflect the current operating circumstances, recently adopted reporting standards, and the implementation of new technologies.

WHEREAS, under the Second Amended Stipulation and Settlement in Docket No. 3617 ("Docket No. 3617 Settlement"), the Commission approved a number of changes in the parameters of an SQ plan that would follow the 2930 SQ Plan.

WHEREAS, subsequent to Commission approval of the Docket No. 3617 Settlement, Narragansett and the Division of Public Utilities and Carriers ("Division") engaged in negotiations aimed at structuring a new SQ plan that achieved the complementary objectives of each party; i.e., the implementation of stringent SQ standards that encourage the Company to maintain and improve its service quality performance, including through the implementation of new practices and technologies, while imposing appropriate penalties for performance that is below average.

WHEREAS, as of the date of this filing, no other party has sought to intervene or to participate in this docket.

NOW THEREFORE, in consideration of the exchange of promises and covenants hereinafter contained, Narragansett enters into this Settlement Agreement ("Settlement") with the Division to resolve all issues associated with Narragansett's proposed service quality plan for the period beginning with the 2005 calendar year and extending through and including the 2009 calendar year. Except as otherwise provided, upon approval by the Commission, the service quality plan incorporated in this Settlement will supersede in its entirety the 2930 SQ Plan. Based on those negotiations, the parties have reached this settlement agreement founded on the following:

1. Continuation of Basic SQ Plan Structure Approved in Docket No. 2930

The Company and Division agree that the new proposed SQ plan should continue to emphasize reliability and customer service performance standards that underscore the importance of assuring consistent, reliable electric service and high quality customer service for the benefit of customers. Further, the parties believe that customers place significant importance on the reliability of the electric service the Company provides. Therefore, the parties propose to continue the relative weighting of penalties under the new SQ plan that was reflected in the 2930 SQ Plan as well as in the August 2 proposal and in the Docket No. 2930 Settlement. Thus, $1.832 million (or 83%) of the maximum annual penalty of $2.2 million is proposed to be allocated equally between two reliability measures (SAIDI and SAIFI), as approved in the Docket No. 3617 Settlement. The remaining $368 thousand (or 17%) would be allocated equally between customer service metrics (i.e., calls answered within 20 seconds and the customer contact survey).

2. Reliability Standards

a. Combining Coastal and Capital Districts

The Company and Division agree that combining the Capital and Coastal districts for purposes of measuring and reporting reliability results on a statewide basis is appropriate. Accordingly, the Company will implement a SQ plan effective commencing January 1, 2005 that reflects a single statewide SAIDI measure and a single statewide SAIFI measure. The maximum potential penalty for each of the two reliability measures will be $916 thousand.

b. Historical Performance Benchmark

The Company and Division agree that in the context of a comprehensive settlement of this docket that it is reasonable to update the historical benchmark period for evaluating SAIDI and SAIFI. Accordingly, the parties agree to establish the reliability performance benchmark based on results for the years 1995-2002.

c. Use of Logarithmic Data

The parties agree that the historical reliability performance data used to establish the minimum and maximum target levels shall be calculated using the natural logarithm of the historical SAIDI and SAIFI values for this period (i.e., 1995 through 2002).

d. Extraordinary Event Criteria

The parties agree that the Company shall continue to apply the current Extraordinary Event criteria when reporting its reliability results. In addition, the Company shall also annually report, for information purposes, annual SAIDI and SAIFI values calculated under the Institute of Electrical and Electronics Engineers, Inc. ("IEEE") Standard 1366-2003, *Guide for Electric Power Distribution Reliability Indices* ("IEEE Std. 1366-2003") methodology, including the segmentation of those days that would qualify as Major Event Days under that standard. The parties also agree that the Company may petition the Commission no sooner than two years after the date of this Agreement to modify the Company's SQ plan to reflect the adoption of the applicable IEEE Std. 1366 reliability reporting methodology. The Company shall have the burden of proof with respect to any such petition, and the Division shall be free to take any position on such petition.

3. Customer Service Standards

a. Historical Performance Benchmark

The parties agree that it is appropriate to expand the period used to establish the historical performance benchmarks for the two customer service standards to include additional years. Doing so provides a more robust historic data set against which to assess the Company's performance, and takes into account the implementation of improved practices and technologies that affect the Company's performance going forward. Accordingly, the benchmarking periods for both measures will be updated up to and through the end of 2004 (1996-2004 for calls answered; 1997-2004 for customer contact survey).

b. Inclusion of VRU Calls

In 2000, Narragansett implemented a voice response unit ("VRU") in its customer service call center. The VRU allows customers the option of speaking directly with a customer service representative, or, alternatively, customers may elect to complete their respective transactions through the automated options offered by the VRU. In the past few years, the Company has seen an increase in the number of calls that customers complete through the VRU. Therefore, in order to more accurately reflect the totality, and true nature, of the calls being handled by the Company's customer service call center, the parties have agreed that calls completed through the VRU should be included in the measure of calls answered within 20 seconds.

4. Reduction of Offsets

The parties also agree that as part of the comprehensive settlement of all of the issues in this docket, the maximum potential offset that can be earned with respect to any performance metric shall be set at 25% of the maximum penalty for that metric. This is a substantial reduction from the maximum potential offset of 75% under the 2930 SQ Plan. Other than the reduction in the maximum potential offset, the parties do not propose to change any other provision affecting the SQ plan from what was approved in the Docket No. 3617 Settlement, including the allocation between metrics of the maximum penalty amount (83%, or $1.832 million, to reliability, and 17%, or $368 thousand, to customer service), and the provision that offsets can be used only in the year in which they are earned.

5. Proposed New Service Quality Plan

As described above, Narragansett and the Division have reached agreement on a new SQ plan to become effective January 1, 2005. Attachment 1 hereto contains the detailed provisions of the Company's new proposed SQ plan. Those provisions reflect a full and complete description of the plan. Such new SQ plan reflects several changes and updates from the currently effective SQ plan, and adoption of the new SQ plan would resolve all outstanding issues in this docket.

A summary of the SQ plan agreed to by the Company and the Division is set forth in the following table.

Metric	Max. Penalty ($000)	Max. Offset ($000)	Historical Benchmark Period	Other Proposed Changes
Company Duration (SAIDI)	$916	$229	1995-2002	Use of lognormal data to set performance standards
Company Frequency (SAIFI)	$916	$229	1995-2002	Use of lognormal data to set performance standards
Calls Answered in 20 Seconds	$184	$46	1996-2004	Include VRU calls
Customer Contact Survey	$184	$46	1997-2004	
Total	$2,200	$550		

Table 1: Proposed SQ Plan

6. Other Provisions

(a) Unless expressly stated herein, the making of this Settlement establishes no principles and shall not be deemed to foreclose any Party from making any contention in any other proceeding or investigation.

(b) This Settlement is the product of settlement negotiations. The content of those negotiations is privileged and all offers of settlement shall be without prejudice to the position of any Party.

(c) This Settlement is submitted on the condition that it be approved in full by the Commission, and on the further condition that if the Commission does not approve the Settlement in its entirety, the Settlement shall be deemed withdrawn and shall not constitute a part of the record in any proceeding or be used for any purpose, unless all Parties agree to Commission modifications.

(d) Any number of counterparts of this agreement may be executed, and each shall have the same force and effect as an original instrument, and as if all the parties to all the counterparts had signed the same instrument.

Respectfully submitted,

The Narragansett Electric Company
By its Attorneys

Thomas G. Robinson
Laura S. Olton

Thomas G. Robinson
Laura S. Olton

December 29, 2004

The Division of Public Utilities and Carriers
By its Attorney

Leo Wold, 3613
Special Assistant Attorney General

December 26, 2004

Attachment 1

Proposed New Service Quality Plan
For
The Narragansett Electric Company

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

The Narragansett Electric Company ("Narragansett" or the "Company") shall establish the performance standards for reliability and customer service that are set forth in this document. The standards are designed as a penalty-only approach, under which the Company would be penalized if its performance did not meet the standards. The Company receives no reward for performance which exceeds the standards. However, positive performance in one category can be used to offset penalties in other categories within a given year. The Company shall file annually by May 1 a report of its performance during the prior calendar year under the performance standards in this plan. Any net penalty balance reflected in the Company's annual report shall be credited to customers in a manner determined by the Rhode Island Public Utilities Commission (the "Commission") at that time.

The maximum penalty authorized under the standards set forth below is $2.2 million per year. The performance standards set forth below shall be in effect for the calendar year 2005 and continue through 2009 or until they are modified by the Commission.

NOTE: When interpreting the performance standards that follow, please note that pages 6 through 9 of this Exhibit contain definitions of terms used in the standards.

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

FREQUENCY OF INTERRUPTIONS PER CUSTOMER SERVED

Year	SAIFI*
2002	0.98
2001	1.11
2000	1.09
1999	1.05
1998	0.89
1997	0.91
1996	1.03
1995	1.36

Log Average	0.0433
Log Std. Dev.	0.1328

	-2 Std Dev.	-1 Std Dev.	Mean	+1 Std Dev.	+2 Std Dev.
Log Normal	-0.222	-0.089	0.043	0.176	0.309
SAIFI	0.80	0.91	1.04	1.19	1.36

PERFORMANCE STANDARD – SAIFI (System Average Interruption Frequency Index):

SAIFI Company Target	(Penalty)/ Offset
More than 1.36	($916,000)
1.20 – 1.36	linear interpolation
0.91 – 1.19	$0
0.80 – 0.90	linear interpolation
Less than 0.80	$229,000

* The target bands are calculated considering the lognormal nature of the data. To do this, the lognormal mean and lognormal standard deviation are calculated and applied in lognormal space, which is done by applying the mean, 1 standard deviation, and 2 standard deviations and then converting back to normal space. Interruptions from "extraordinary events" are excluded, as described in the attached criteria.

$$\text{SAIFI} = \frac{\text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

DURATION OF INTERRUPTIONS PER CUSTOMER SERVED

Year	SAIDI*
2002	71.1
2001	69.0
2000	74.4
1999	68.4
1998	42.2
1997	59.5
1996	72.8
1995	63.7

Log Average	4.1627
Log Std. Dev.	0.1851

	-2 Std Dev.	-1 Std Dev.	Mean	+1 Std Dev.	+2 Std Dev.
Log Normal	3.793	3.978	4.163	4.348	4.533
SAIDI	44.4	53.4	64.2	77.3	93.0

PERFORMANCE STANDARD – SAIDI (System Average Interruption Duration Index):

SAIDI Company Target	(Penalty)/ Offset
More than 93.0	($916,000)
77.4 – 93.0	linear interpolation
53.4 – 77.3	$0
44.4 – 53.3	linear interpolation
Less than 44.4	$229,000

* The target bands are calculated considering the lognormal nature of the data. To do this, the lognormal mean and lognormal standard deviation are calculated and applied in lognormal space, which is done by applying the mean, 1 standard deviation, and 2 standard deviations and then converting back to normal space. Interruptions due to "extraordinary events" are excluded, as described in the attached criteria.

$$\text{SAIDI (minutes)} = \frac{\text{Total Customer Minutes Interrupted}}{\text{Total Number of Customers Served}}$$

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

CUSTOMER CONTACT SURVEY

Year	% Satisfied*
2004	76.5% (estimated)
2003	79.3%
2002	76.0%
2001	77.3%
2000	83.2%
1999	82.1%
1998	77.8%
1997	79.5%
Mean	79.0%
Standard Deviation	2.4%

PERFORMANCE STANDARD – Customer Contact:

% Satisfied Target	(Penalty)/ Offset
Less than 74.2%	($184,000)
74.2% – 76.5%	linear interpolation
76.6% – 81.4%	$0
81.5% – 83.8%	linear interpolation
More than 83.8%	$46,000

* The calculations are based on responses from customers of Narragansett based on surveys performed by an independent third party consultant. A sample of customers who have contacted the call center are surveyed in order to determine their level of satisfaction with their contact. Eight types of transactions are included in the survey, and the overall results are weighted based on the number of these transactions actually performed at the call center during the year.

The percent satisfied represents the responses in the top two categories of customer contact satisfaction under a seven-point scale, where 1=extremely dissatisfied and 7=extremely satisfied.

The results for 2004 are estimated based on actual results through November 2004 and projected results for December 2004. This will be revised to reflect final results through December 2004 in a filing to be made with the Commission prior to May 1, 2005.

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

TELEPHONE CALLS ANSWERED WITHIN 20 SECONDS

Year	Percent of Calls Answered Within 20 Secs*
2004	93.0% (estimated)
2003	93.3%
2002	84.0%
2001	50.4%
2000	76.7%
1999	76.9%
1998	80.9%
1997	76.7%
1996	70.2%
Mean	78.0%
Standard Deviation	12.2%

PERFORMANCE STANDARD – Telephone Calls Answered within 20 Seconds:

% Calls Answ Within 20 Seconds Target	(Penalty)/ Offset
Less than 53.6%	($184,000)
53.6% – 65.7%	linear interpolation
65.8% – 90.2%	$0
90.3% – 100.0%	linear interpolation, to a maximum of $46,000 at 100.0%

* The percent of calls answered within 20 seconds is calculated by dividing the number of calls answered within 20 seconds by the total number of calls answered during the year. "Calls answered" include calls answered by a customer service representative ("CSR") and calls completed within the Voice Response Unit ("VRU"). The time to answer is measured once the customer makes a selection to either speak with a CSR or use the VRU. VRU calls are included beginning in the year 2000.

The results for 2004 are estimated based on actual results through November 2004 and projected results for December 2004. This will be revised to reflect final results through December 2004 in a filing to be made with the Commission prior to May 1, 2005.

$$\text{Percent of Calls Answered Within 20 Seconds} = \frac{\text{Total Calls Answered Within 20 Seconds}}{\text{Total Calls Answered}}$$

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

DEFINITIONS OF PERFORMANCE STANDARD MEASUREMENTS

INTERRUPTION EVENT

The loss of service to more than one (1) customer for more than one (1) minute.

INTERRUPTION DURATION

The period of time, measured in minutes, from the initial notification of the interruption event to the time when service has been restored to the customers.

CUSTOMER

An active bill account with an active meter at a premise.

CUSTOMER COUNT

The number of customers either served or interrupted depending on usage.

TOTAL NUMBER OF CUSTOMERS SERVED

The average number of customers served during the reporting period. If a different customer total is used, it must be clearly defined within the report.

TOTAL NUMBER OF CUSTOMERS INTERRUPTED

The sum of the customers losing electric service for any defined grouping of interruption events during the reporting period.

TOTAL CUSTOMER MINUTES INTERRUPTED

The product of the number of customers interrupted and the interruption duration for any interruption event. Also, the sum of those products for any defined grouping of interruption events.

EXTRAORDINARY EVENTS

A particular interruption event will be considered extraordinary, and will not count towards the Reliability Performance Standards, if it meets one of the following criteria:

(1) It was the result of a major weather event which causes more than 10% of a district or the total company customers to be without service at a given time.

(2) It was due to the failure of other companies' supply or transmission to Narragansett Electric customers and restoration of service was beyond the reasonable control of the Company and its employees.

(3) It occurred because of an extraordinary circumstance, including, without limitation, a major disaster, earthquake, wild fire, flood, terrorism, or any other event beyond the reasonable control of the Company.

MAJOR EVENT

Designates an event that exceeds reasonable design and or operational limits of the electric power system. A Major Event includes at least one Major Event Day.

MAJOR EVENT DAY

A day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

i denotes an interruption event

r_i	=	Restoration Time for each Interruption Event
CI	=	Customers Interrupted
CMI	=	Customer Minutes Interrupted
N_T	=	Total Number of Customers Served for the Area

SAIFI (System Average Interruption Frequency Index)

The system average interruption frequency index indicates how often the average customer experiences a sustained interruption over a predefined period of time. Mathematically, this equation is given in (1).

$$SAIFI = \frac{\sum \text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}} \qquad (1)$$

To calculate the index, use equation (2) below.

$$SAIFI = \frac{\sum N_i}{N_T} = \frac{CI}{N_T} \qquad (2)$$

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

SAIDI (System Average Interruption Duration Index)

This index indicates the total duration of interruption for the average customer during a predefined period of time. It is commonly measured in customer minutes or customer hours of interruption. Mathematically, this equation is given in (3).

$$SAIDI = \frac{\Sigma \text{ Customer Interruption Durations}}{\text{Total Number of Customers Served}} \tag{3}$$

To calculate the index, use equation (4).

$$SAIDI = \frac{\Sigma r_i N_i}{N_T} = \frac{\text{CMI}}{N_T} \tag{4}$$

CUSTOMER CONTACT SURVEY

The calculations are based on responses from customers of Narragansett, based on surveys performed by an independent third party consultant. A sample of customers who have contacted the call center are surveyed in order to determine their level of satisfaction with their contact. The Company will maintain the same levels of statistical precision of the results as in prior surveys. Eight types of transactions are included in the survey, and the overall results are weighted based on the number of these transactions actually performed at the call center during the year. The eight types of transactions are power interruptions, meter on, meter off, meter exchange, collection, payment plan, meter reread, and meter test.

The percent satisfied represents the responses in the top two categories of customer contact satisfaction under a seven-point scale, where 1=extremely dissatisfied and 7=extremely satisfied.

TELEPHONE CALLS ANSWERED WITHIN 20 SECONDS

The percent of calls answered within 20 seconds is calculated by dividing the number of calls answered within 20 seconds by the total number of calls answered during the year. "Calls answered" include calls answered by a customer service representative ("CSR") and calls completed within the voice response unit ("VRU"). Abandoned calls are not considered. The time to answer is measured once the customer makes a selection to either speak with a CSR or use the VRU. VRU calls are included beginning in the year 2000.

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

LINEAR INTERPOLATION

(1) The actual performance or penalty each year will be calculated and the result will be scaled or interpolated linearly between the relevant two points of the results range and the relevant two points on the dollar range.

(2) The method of determining the actual penalty, or offset, of each performance standard is determined by multiplying the value of the penalty, or offset, by the absolute value of the actual performance indicator minus the value of the first standard deviation from the mean of that indicator, divided by the value of the second standard deviation of the mean of that indicator minus the value of the first standard deviation from the mean of that indicator.

$$\$\text{ Penalty or Offset} = \text{Penalty or Offset }\$\text{ Value} \times \frac{\text{Actual} - 1^{st}\text{ standard deviation}}{2^{nd}\text{ standard deviation} - 1^{st}\text{ standard deviation}}$$

THE NARRAGANSETT ELECTRIC COMPANY
SERVICE QUALITY PLAN

ADDITIONAL REPORTING CRITERIA

1. Each quarter, the Company will file a report of 5% of all circuits designated as worst performing on the basis of customer frequency.

   Included in the report will be:
   1. The circuit id and location.
   2. The number of customers served.
   3. The towns served.
   4. The number of events.
   5. The average duration.
   6. The total customer minutes.
   7. A discussion of the cause or causes of events.
   8. A discussion of the action plan for improvements including timing.

2. The Company will track and report monthly the number of calls it receives in the category of Trouble, Non-Outage. This includes inquiries about dim lights, low voltage, half-power, flickering lights, reduced TV picture size, high voltage, frequently burned out bulbs, motor running problems, damaged appliances and equipment, computer operation problems and other non-Interruptions related inquiries.

3. The Company will report its annual meter reading performance as an average of monthly percentage of meters read.

4. The Company will also report annually the annual SAIDI and SAIFI values calculated under the Institute of Electrical and Electronics Engineers, Inc. ("IEEE") Std. 1366-2003 methodology, including the segmentation of those days that would qualify as Major Event Days under that standard.

Information Request DTE-MECo 1-5

Request:

Please identify each and every state, commonwealth, or federal district that has adopted IEEE 1366-2003 in some form for reporting purposes for all electric distribution companies within its jurisdiction. (Do not include any state, commonwealth, or federal district that has adopted a variation or part of IEEE 1366-2003 for one, two or a few companies but not for all.) Explain the difference between what was adopted in these states, commonwealths, or federal district and what is proposed in this docket. For each and every state, commonwealth, and federal district, identified, provide copies of the enabling legislation, Order, or regulation adopting IEEE 1366-2003.

Response:

The Company is aware of two states, Utah and Delaware, which have adopted the IEEE Std.1366-2003 as described in question 1-5. Please find attached to this response a memorandum from the Utah Division of Public Utilities to the Public Service Commission recommending the change to the IEEE Major Event Day definition for PacifiCorp, the only jurisdictional distribution company in Utah, and PSC Order No. 6745 from Delaware.

In addition to the two utilities that have adopted IEEE 1366-2003 as described in question 1-5, two other states, Washington and Montana, have partially adopted IEEE 1366-2003. All utilities in the state of Washington use IEEE Std. 1366-2003 for reliability calculations. Please find attached to this response the testimony of Douglas Kilpatrick before the Washington Utilities and Transportation Commission regarding the recommendation of using IEEE 1366 for reliability metrics.

Please contact the following individuals for more information:

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Information Request DTE-MECo 1-5 (continued)

In Montana, the commission issued a notice of adoption (attached MAR notice number 38-2-187) to Administrative Rules of Montana (ARM) 38.5.8601 to 38.5.8619 that states:

"RULE I (38.5.8601) DEFINITIONS In this subchapter the following definitions shall apply unless the context otherwise clearly demands:

(1) and (2) remain as proposed.
(3) "Major event" means a catastrophic event that:
(a) for regulated electric utilities that have adopted the Institute of Electrical and Electronic Engineers Guide for Electric Power Distribution Reliability Indices, meets the definition of "major event day," standard 1366-2003; or
(b) for regulated electric utilities that have not adopted the Institute of Electrical and Electronic Engineers Guide for Electric Power Distribution Reliability Indices:
(a) (i) exceeds the design limits of the electric power system;
(b) (ii) causes extensive damage to the electric power system; and
(c) (iii) results in a simultaneous sustained electric service interruption to more than 10% of the customers in an operating area.
(4) remains as proposed."

Northwestern Energy is the largest jurisdictional utility in Montana, with 65 to 70% of electric customers, and it uses IEEE 1366-2003.

Prepared by or under the supervision of: Cheryl A. Warren

State of Utah
Department of Commerce
Division of Public Utilities

RUSSELL SKOUSEN
Executive Director

JASON PERRY
Deputy Director

IRENE REES
Director, Division of Public Utilities

JON HUNTSMAN Jr.
Governor

GARY HERBERT
Lieutenant Governor

Memorandum

TO: Public Service Commission

FROM: Division of Public Utilities
Irene Reese, Director
Energy Section
Abdinasir Abdulle, Technical Consultant
Charles Peterson, Utility Analyst
Rea Petersen, Administrative Assistant
Artie Powell, Acting Manager

DATE: February 23, 2005

SUBJECT: Advice Filing 04-13 – Docket No. 98-2035-04 – Rule 25 – Customer Guarantees and Schedule 300 – Regulation Charges

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ISSUE

On December 2, 2004, PacifiCorp (Company) filed an Advice Filing 04-13 –Docket No. 98-2035-04 proposing some revisions to Electric Service Regulation 25 and Schedule 300 upon the expiration of the Company's five-year merger commitment on March 31, 2005. Specifically, the Company proposes several changes to its customer guarantees, network performance standards, and customer service performance standards. Additionally, the Company proposes a change in the definition of a Major Event. Finally, the Company proposes a three-year term for the modified program with an effective date of April 1, 2005. The Division of Public Utilities was asked to investigate and review Tariff compliance and report its recommendations by March 25, 2005.

RECOMMENDATION

The Division of Public Utilities recommends that the Commission approve, with the modifications specified below, the Advice Filing 04-13, – Docket No. 98-2035-04 – Rule 25 – Customer Guarantees and Schedule 300 – Regulation Charges, with an effective date of April 1, 2005. In summary, the Division recommends the following changes to the Company's proposal:

1) On page 8 of the filing, the language should be changed to reflect that the Company will respond to 100% of Commission complaints within thirty days.

2) The language used in NPS4 should be expanded to read "the Company will continue to select a maximum of five under-performing circuits in Utah on an annual basis and it will undertake corrective measures to reduce the circuit performance indicator (CPI) within two years. After no more than an additional three years, the Company will measure the current CPI score for its targeted 20% improvement….."

3) In relation to CS3, The Company should track the number of customers whose power was disconnected for non-payment and the length of time it takes to switch their power back on. The Division recommends that the Company report this information to the Commission on an annual basis.

4) Regarding CG7, The Division recommends that the Company continue to provide two working days notice for planned interruptions. The Division also recommends that the Company collect data on the number of business customers affected by planned interruptions and length of notice time provided. This information should be reported to the Commission annually.

5) The Division recommends that the Company continue providing Quarterly reports on the Customer Service Commitments to the Commission.

DISCUSSION

In Bob Moir's direct testimony of Docket No. 98-2035-04, the Company agreed to implement seven Performance Standards and eight Customer Guarantees[1] for five years beginning February 29, 2000 and ending March 31, 2005. The Performance Standards describe what the customers can expect in terms of overall level of service provided by the Company. The Customer Guarantees are the Company's guarantees to individual customers regarding the quality of their interaction with the Company. The purpose of these merger commitments was to improve service to customers and to emphasize to Company employees that customer service is a top priority. These Service Standards or merger commitments will expire on March 31, 2005.

In this filing, the Company proposes a continuation of both the Performance Standards and the Customer Guarantees with some modifications. The proposed modifications, other than a change in the Major Event Definition, are as follows.

Customer Guarantee 1. Restoring Supply After an Outage: The Company proposes to continue this guarantee with no changes.

Customer Guarantee 2. Appointments: The Company proposes to schedule customers' appointments within a two-hour time frame. Previously, the Company offered customers morning (8:00 A.M. to 1:00 P.M.) appointments or afternoon (1:00 P.M. to 5:00 P.M.) appointments. The proposed change to this guarantee will reduce the length of time customers have to wait for their appointments. Hence, the Division believes that the proposed time frame for appointments is an improvement to this guarantee and recommends the Commission's approval.

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[1] See attachment A.

Customer Guarantee 3. Switching on the Customer's Power: There are two proposed changes to this guarantee. First, the Company proposes to explicitly exclude guarantee payments for failure to switch on power within 24 hours if the customer was disconnected for non-payment, subterfuge or theft/diversion of service. However, the Company will continue to make every reasonable effort to switch on power for these customers within 24 hours after payment is received or arrangements are made for payments. Second, the Company also proposes a flat $50 guarantee payment for failure to switch power on within twenty-four hours for new customers. This replaces the current compounding of $25 every 12 hours beyond 24 hours.

With regard to the exclusion provision, on page 4 of the filing and in a meeting with the Commission, Division, Committee, and other parties, the Company indicated that it has voluntarily made guarantee payments to customers whose power had been disconnected for non-payment. The Company sees no reasonable justification to continue voluntary payments to customers who are not paying their bills. In its response to the Division's data request, the Company indicated that about 40% of Customer Guarantee 3 payments were paid out to customers who were disconnected for non-payment. The Division does not oppose this change, but because 40% represents a significant portion of total terminations, the Division recommends that the Company track the number of customers in this category and the length of time it takes to switch their power on and report this information to the Commission annually

With regard to the payment schedule, based on its experience in administering this guarantee, the Company claims that most of the customers who have received payments for failures under this guarantee have not been inconvenienced or economically impacted by a failure to switch on power within 24 hours. According to the Company, it is common for a customer to request to have power switched on by a given date, but that customer may not actually occupy the site until days after the switch on date, so there is no significant impact to customers if the power is not switched on within 24 hours.

Additionally, of the 12 utilities that the Company surveyed[2], only four are providing any type of guarantee on service activation. Each of these four utilities pays a flat fee averaging $40 per incident.

In a response to the Division's data request, the Company stated that it paid out a total of $10,075 for failures of this guarantee in FY2004. If the compounding feature of the payment were eliminated, the payment would have been $5,000. The Division notes that the Company switched on power within the guaranteed 24 hours 99.7% of the time (Company's FY2004 annual report on performance). The Division concludes that the proposed change appears to simplify the administration of this guarantee and is more in line with industry practices. Furthermore, the Division believes the reduction in the amount of money towards failure of this guarantee ($5075) is relatively small that the individual economic impact of this proposed change is minimal. Therefore, the Division recommends the Commission approve the proposed changes for this guarantee with the noted reporting requirements.

Customer Guarantee 4. Estimates for Providing a New Supply: The Company proposes a change to simplify the administration of this Customer Guarantee. Under the new proposal, the Company will provide a written estimate to customers within 15 working days after the initial meeting with the customer. Currently, the guarantee requires the Company to contact the customer within two working days to set an appointment and to provide a preliminary estimate within five working days assuming that alterations to the Company's network is not needed. Although the Company indicates it will maintain an internal target to contact customers within two working days

[2] See Attachment B for summary of the Company's survey. In May 2004, the Company identified the US utilities that are offering customer guarantees by reviewing Edison Electric Institute's catalog. The Company then obtained information about these utilities' customer guarantees, which were then compiled into a comparison summary.

to set an appointment, no other utilities surveyed guarantees this kind of timeframe for estimating new power supply.

By reviewing the Company's FY2004 annual report, the Division noted that the Company made more payments under Customer Guarantee 4 than any of the other guarantees (accounting 95.7% in FY03 and 97.7% in FY2004). The problem, in part, arises because this guarantee depends upon a sequence of activities, each to be performed in a timely manner. The structure of this guarantee contributes to the likelihood of guarantee failure. Hence, it is the Division's belief that the proposed change will simplify the administration of this guarantee and recommends the Commission to approve it.

Customer Guarantee 5. Response to Bill Inquiries: The Company proposes to continue this guarantee with no changes.

Customer Guarantee 6. Resolving Meter Problems: The Company proposes to reverse the time it takes to investigate reported problems or to conduct meter tests and report back to the customer from 15 days to 10 days. Given that there were only 15 failures in FY03 and 10 failures in FY04 (Company's FY2004 annual report on performance) for this guarantee, one could reasonably expect that the proposed improvement for this guarantee is achievable. The Division recommends the Commission approve the proposed changes.

Customer Guarantee 7. Planned Interruptions: The Company proposes to change the customer notification time for planned interruptions from two working days to two calendar days. In his Direct Testimony in Docket No. 98-2035-04, Bob Moir wrote

> "*Planned Interruption:* If we need to turn the customer's power supply off for planned maintenance work or testing, we will give the customer at least two days notice."

In interpreting the above quotation, the Company has been providing two working days. To gain some flexibility in scheduling employees, the Company proposes the aforementioned change to this guarantee.

The Division, however, is concerned that two calendar days notice may not give business customers enough time to make the necessary arrangements in employee or production curtailments. In response to a Division data request, the Company indicated that, when businesses are involved in a planned interruption, it usually provides more than the minimum 2-day notice so that businesses can plan accordingly. According to the Company's data response, it is the Company's regular practice to offer business owners the opportunity to reschedule a planned interruption provided that the business reimburses the Company for any overtime costs incurred. The Company further indicated that it "does not track the planned interruption records by customer types that are affected (residential, vs. business)". Although the Division commends the Company's efforts in working with businesses, the Division believes that there is a need for more objective data regarding the number of businesses affected by the planned interruption and the length of notice time per interruption before any changes are made to this guarantee. Therefore, the Division recommends that the Company continue to provide two working days notice for the life of the proposed modified program. The Division also recommends that the Company collect data on the number of business customers affected and length of notice time provided each business, and report this information to the Commission annually.

Customer Guarantee 8. Power Quality Complaint: Because there have been few power quality complaints (46 during FY03 and 204 during FY04) according to the Company's FY2004 annual report on performance and the Company met this guarantee's requirements 100% of the time, the Company proposes eliminating this guarantee. The Company proposes that any power quality complaints can be handled through the Commission's complaint system and the Company will respond to any complaint within three working days. The Division believes that this suggestion is reasonable and recommends that the Commission approve the proposed elimination of this guarantee.

Network Performance Standards

In relation to Network Performance Standards (NPS) 1 and 2, the Company proposes to improve the SAIDI and SAIFI results by 6% to 207 minutes and 2.08 events, respectively within the three-year term of the modified program. Regarding NPS 4, the Company stated in its filing that "the Company will continue to select a maximum of five under-performing circuits in Utah on an annual basis and will undertake corrective measures to reduce the circuit performance indicator (CPI) by 20% within two years. The Company will expand the event inclusions to consider transmission and local transmission outages events, as well events that meet the criteria of the IEEE major event definition." The Division believes that the inclusion of the transmission events represents an improvement to the standard. However, the language for this guarantee should be expanded to read as

> *The Company will continue to select a maximum of five under-performing circuits in Utah on an annual basis and will undertake corrective measures to reduce the circuit performance indicator (CPI) within two years. After no more than an additional three years after the two years, the Company will measure the current CPI score for its targeted 20% improvement.....*

The Company proposes to keep NPS 5 (Restoring Power Outage) unchanged. However, the Company proposes an elimination of NPS 3 (related to MAIFI). The Company believes that the current method of measuring this index (breaker counts) does not provide an accurate measurement of MAIFI. To obtain an accurate measurement of MAIFI would require the addition of momentary detection capability to each circuit, which is a very expensive proposition. Hence the Company proposes to eliminate this standard. The Division sees no reason to oppose the Company's recommendations.

Customer Performance Standards

The Company will retain both Customer Service Performance Standards (CSPS 1 and 2), but proposes changes to both standards. Regarding the standard for telephone performance (CSPS1), the Company proposes that the service level for telephone response be reduced from 80% of calls answered in 20 seconds to 80% of calls answered in 30 seconds. The Company argues that the current standard may actually compromise service quality, because in trying to answer the telephone in a timely manner, customer representatives may put some customers on hold. To avoid this potential problem, the Division thinks the proposed change is reasonable when coupled with a focus on the quality of service that the customer receives. In its filing and in a meeting with the Commission, Division, and Committee, the Company stated that it will monitor customer satisfaction with the Company's Customer Service Associates and the quality of response they receive.

Regarding CSPS2, the Company's proposed change is to include a 95% completion target to the Company's target response to non-disconnect and disconnect complaints. That is, the Company proposes to respond to non-disconnect Commission complaints within 3 working days at least 95% of the time, respond to disconnect Commission complaints within four business hours at least 95% of the time, and resolve Commission complaints within 30 days at least 95% of the time. Rule R745-200-7 requires that the Utility resolve 100% of the Commission complaints within 30 days. The Division recommends that the Company make the appropriate change to the filing to comply with this rule.

Major Event Definition

Besides the Customer Guarantees and the Performance Standards, the Company also proposes changes in the General Exceptions. Specifically, the Company is proposing to change the definition of Major Event to match the IEEE 1366-2003 definition. The IEEE 1366-2003 defines Major Event as "*an event that exceeds reasonable design and or* *operational limits of the electric power system. A Major Event includes at least one Major Event Day".* IEEE 1366-2003 defines a Major Event Day as *"a day in which the system SAIDI exceeded a threshold value, T_{MED}."* A Major event Day is simply a day in which the reliability of the distribution system is much worse than normal.

Currently, different utilities define Major Event differently and use different data collection methods. According to IEEE, this lack of consistency makes it difficult to compare indices between utilities (even if the customers served by these utilities have the same reliability experience) and to develop meaningful trending and service quality targets. Consequently, the IEEE Working Group on System Design (Working Group) tried to develop a methodology that will yield better comparability and target setting. The Working Group established criteria that the method should meet: 1) be fair to all utilities regardless of size, 2) allow segmentation of reliability data into normal and abnormal categories, based on the identification of outlier events that cause Major Event Days, 3) allow use of normalized indices for internal and external goal setting, 4) be consistent for various amounts of data availability and for all utilities, and 5) be easy to understand and execute. The Working Group selected the 2.5 Beta Method (described below) as the method that best meets these criteria.

Two and One-Half Beta Method

In an attempt to determine the most objective method, the Working Group obtained and exhaustively analyzed reliability data from 37 utilities. The Working Group found that the reliability data, in this case the daily SAIDI values, closely approximates a log normal distribution. The 2.5 Beta Method is based on two facts. First, if a random variable has a log-normal distribution, the natural log of this random variable is said to have a normal distribution. Second, given that the daily SAIDI measures follow a log-normal distribution, the probability of a day being defined as a major event day is less than 1%.

Assuming the daily SAIDI follow a log-normal distribution, any day with a SAIDI greater than the threshold value, T_{MED}, is said to be a Major Event. The Major Event identification threshold, T_{MED}, is calculated using the following procedure:

1. Assemble the preceding three to five years of daily SAIDI values,
2. Remove from the data set any day in which the daily SAIDI value was zero,
3. Take the natural log of each of the daily SAIDI values,
4. Calculate the mean, α, and the standard deviation, β, of the natural logs of the daily SAIDI values, and
5. Calculate the threshold, $T_{MED} = e^{(\alpha+2.5\beta)}$

Justification of 2.5 Beta Method

There are two underlying assumptions of 2.5 Beta Method. First, if a random variable has a log-normal distribution, the natural log of this random variable is said to have a normal distribution. Second, the daily SAIDI values exhibit a log-normal distribution and thus the natural log of the daily SAIDI value follow a normal distribution. The relationship between the two distributions can be used to assign probabilities to individual events, specifically, to the event $T_{MED} = e^{\alpha+2.5\beta}$ where α and β are parameters describing the lognormal distribution. In particular we want to know the probability that the SAIDI measure for any given day will be greater than T_{MED}. As it turns out, this probability is less than one percent. A more detailed discussion of the relationship between the two distributions mentioned above can be found in Appendix A.

Test of Normality

For the 2.5 Beta Method to be valid, the daily SAIDI data must follow a log-normal distribution. That is, the log of the daily SAIDI data must follow a normal distribution. Using SAIDI data provided by PacifiCorp, the Division performed a normality test to determine if, under normal conditions, the natural log of PacifiCorp's daily SAIDI values approximate a normal distribution (testing if the daily SAIDI values have log-normal distribution will lead to the same conclusion). The data covered the period from January 2000 to May 2003.

To implement the test, the Division used a Box-and-Whisker plot to identify any outliers in the data set. SAIDI values determined to be outliers were removed from the data set. Removing the outliers was essential to ensure that the remaining data represented "normal" operating conditions. To test for normality, the Division used the Chi-square goodness of fit, Kolmogorov-Smirnov, and Anderson-Darling normality tests. The null hypothesis tested was that the natural log of PacifiCorp's daily SAIDI values is normally distributed. Both the Chi-square and the Kolmogorov-Smirnov failed to reject the null hypothesis (at $p<0.05$ and $p<0.01$, respectively). The Anderson-Darling failed to accept the null hypothesis. However, for large data sets, the Anderson-Darling test is sensitive in detecting even slight deviations from normality. Hence, based on the results of the Chi-square and the Kolmogrov-Smirnov normality tests, the Division concludes that, under normal conditions, the natural log of PacifiCorp's daily SAIDI values is normally distributed and the use of the 2.5 Beta Method is justified. Therefore, the Division recommends the Commission to approve the proposed change in the major event definition.

CC: Rea Petersen, DPU
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APPENDIX A

TWO AND ONE-HALF BETA METHOD

If the random variable X = lnY has a normal distribution, then Y is said to have a lognormal distribution. This relationship between the two distributions can be used to assign probabilities to events associated with Y, specifically, to the event $T_{MED} = e^{\alpha + 2.5\beta}$ where α and β are parameters describing the lognormal distribution. In particular we want to know the probability that the SAIDI measure for any given day will be greater than T_{MED}.

Normal Distribution

If the random variable X has a normal distribution with mean μ and variance σ^2 then we write $X \sim N(\mu, \sigma^2)$. Where "~" should be read as "is distributed as". The probability density function ("pdf") is given by

$$f(x) = \frac{1}{\sqrt{2\pi\sigma^2}} Exp\left[-\frac{1}{2\sigma^2}(x-\mu)^2\right] \tag{1}$$

While the probability density function ("pdf") appears complicated, it turns out to be very convenient to work with. For example, one characteristic of the normal distribution is any linear transformation of a normal random variable is itself a normal random variable. In particular, the Z-score

$$Z = \frac{X-\mu}{\sigma} \tag{2}$$

is normally distributed with mean 0 and variance 1: Z ~ N(0, 1). Thus, the probability that the random variable X is less than some number x, is equal to the probability that Z (the Z-score) is less than the number $z = \frac{x-\mu}{\sigma}$. That is,

$$
\begin{aligned}
P(X \leq x) &= P\left(\frac{X-\mu}{\sigma} \leq \frac{x-\mu}{\sigma}\right) \\
&= P(Z \leq z) \\
&= \Phi(z)
\end{aligned} \tag{3}
$$

Lognormal Distribution

If the random variable X has a normal distribution as described above, and X = lnY or, in other words, Y = e^X, then Y is said to have a lognormal distribution with mean

$$E(Y) = e^{\mu + \frac{1}{2}\sigma^2} = Exp\left[\mu + \frac{1}{2}\sigma^2\right] \tag{4}$$

and variance

$$
\begin{aligned}
Var(Y) &= e^{2\mu + 2\sigma^2} - e^{2\mu + \sigma^2} \\
&= Exp\left[2\mu + 2\sigma^2\right] - Exp\left[2\mu + \sigma^2\right]
\end{aligned} \tag{5}
$$

The pdf for the lognormal distribution is

$$f(y) = \frac{1}{y\sqrt{2\pi\sigma^2}} Exp\left[-\frac{1}{2\sigma^2}(\ln y - \mu)^2\right] \tag{6}$$

Probabilities for the lognormal distribution can be defined in terms of the normal distribution. For example, the probability that Y is less than some number y is equal to the probability that X = lnY is less than x = ln$y$:

$$
\begin{aligned}
P(Y \leq y) &= P(\ln Y \leq \ln y) \\
&= P(X \leq x)
\end{aligned} \tag{7}
$$

And following Equation (3), we can say

$$P(X \leq x) = P(Z \leq z) = \Phi(z) \tag{8}$$

where $z = \frac{\ln y - \mu}{\sigma}$.

Two and One-Half Beta Rule

The Two and One-Half Beta rule is defined by the value $T_{MED} = e^{\alpha + 2.5\beta}$. In the case of PacifiCorp's major event definition, any daily SAIDI measure, say "y", which exceeds T_{MED}, is classified as a major event day. For example, suppose we have a series of daily SAIDI measures $y_1, y_2, \ldots, y_n$. It is assumed that the SAIDI measures follow a lognormal distribution so that, $x_i = \ln y_i \;\; for \; i = 1, 2, \cdots, n$, will follow a normal distribution.

If we assume the mean and standard deviation of the normal distribution are α and β respectively, then the probability that the SAIDI for any given event exceeds T_{MED} can be easily found using the relationship between the normal and lognormal distributions. That is, for a given event whose SAIDI measure is equal to y, the probability that y is greater than T_{MED} is given by,

$$
\begin{aligned}
P(y > T_{MED}) &= P\left(y > e^{\alpha + 2.5\beta}\right) \\
&= P(\ln y > \alpha + 2.5\beta) && \textit{Taking logs} \\
&= P(x > \alpha + 2.5\beta) && \textit{By definition} \qquad (9) \\
&= P\left(z > \frac{\alpha + 2.5\beta - \alpha}{\beta}\right) && \textit{Using Z-Score} \\
&= P(z > 2.5) && \textit{Simplifying}
\end{aligned}
$$

The probability that z exceeds 2.5 is less than 1 percent.[3] In other words, we would expect that less than 1 percent of a large sample of SAIDI measures would exceed T_{MED}. Thus the conclusion is drawn that for any given day, if the day's SAIDI measure exceeds T_{MED}, the day should be classified as a major event day.

Since α and β are not known, they will need to be estimated for a given sample of SAIDI measures. These estimates can be defined by $\hat{\alpha} \; and \; \hat{\beta}$ respectively, where $\hat{\alpha}$ is equal to the arithmetic mean of the natural log of the SAIDI measures and $\hat{\beta}$ is equal to the standard deviation:

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[3] From the standard normal table, which can be found in most elementary statistics texts, the probability that z exceeds 2.5 is equal to 0.0062.

$$\hat{\alpha} = \frac{1}{n}\sum_{i=1}^{n} \ln y_i$$

$$\hat{\beta} = \sqrt{\frac{1}{n-1}\sum_{i=1}^{n}\left(\ln y_i - \hat{\alpha}\right)^2} \tag{10}$$

Exhibit T-___ (DEK-1T)
Docket No. UG-040640, et al.
Witness: Douglas Kilpatrick

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, INC. Respondent.	DOCKET NO. UG-040640 DOCKET NO. UE-040641 *(consolidated)*

TESTIMONY OF

DOUGLAS KILPATRICK

STAFF OF THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Major and Catastrophic Storm Damage, Reliability Maintenance, and the Tree Watch Program

September 23, 2004

Q. Please state your name and business address.

A. My name is Douglas E. Kilpatrick. My business address is Chandler Plaza Building, 1300 South Evergreen Park Drive Southwest, P. O. Box 47250, Olympia, Washington 98504-7250.

Q. By whom are you employed and in what capacity?

A. I am employed by the Washington Utilities and Transportation Commission as the Assistant Director for Emergency and Risk Management. My current assignments include liaison with the State Military Department - Emergency Management Division, responsibility for the agency's safety and wellness programs, development and maintenance of the agency's hazard mitigation and emergency plans, and other duties. For purposes of this docket, I was asked by the Regulatory Services Staff (Staff) to analyze and comment on Puget Sound Energy's (PSE or the Company) electric service reliability.

Q. How long have you been employed by the Commission?

A. Since June 1996. Prior to coming to work at the Commission I worked for Pacific Gas and Electric Company as a key account representative between January 1980 and July 1987, providing new business services for commercial and industrial customers. From December 1987 to June 1996, I worked for the Washington State Energy Office as the manager of its engineering staff and as the Assistant Director of the Energy Management Division.

Q. Would you briefly state your educational background?

A. I attended Humboldt State University and received a Bachelor of Science in Environmental Resources Engineering in 1982. I am also a licensed professional mechanical engineer, having received my license from Washington State in 1990.

Q. Have you held any other positions with the Commission since you began employment there?

A. Yes, I was originally hired as the agency's Electric Industry Coordinator. In this position, I supervised the agency's staff responsible for all aspects of regulation of jurisdictional electric companies. I held this position from June 1996 to October 2000. I then became the Commission's Director of Pipeline Safety. This position involved program leadership and development for the agency's comprehensive safety regulation of natural gas and hazardous liquid pipeline companies within the state. In February 2003, I assumed my current position.

Q. Have you testified before this Commission in any prior proceedings?

A. Yes, I presented testimony on behalf of Staff in the application of PacifiCorp for authorization to merge with Scottish Power (Docket No. UE-981627). In that case, I presented Staff's recommendation that the Commission approve the application according to the terms of a Stipulation Staff entered with the companies.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will cover two topics related to electric system reliability. First, I will provide testimony on the topic of electric system reliability metrics and PSE's system reliability performance in recent years. Second, I will comment on the Company's proposal to continue its Tree Watch Program.

I. Electric System Reliability Metrics

Q. Why is it important to consider reliability metrics in this case?

A. In her direct testimony, Company witness McLain proposes that the Commission change the current definitions used by the Company for identifying losses associated with catastrophic, or extraordinary events. (Exhibit No. ___(SML-1CT), pages 28 through 31). The purpose of my testimony is to recommend an alternative to these proposed definitions, based on a recently adopted industry standard.

Q. What reliability metrics are you recommending be used by PSE?

A. The reliability indices I recommend be used for measurement and comparison purposes are those established by the Institute of Electrical and Electronic Engineers (IEEE), Inc. in its Standard (Std) 1366-2003, entitled *IEEE Guide for Electric Power Distribution Reliability Indices*. The IEEE is a professional organization that develops industry-wide standards in this area. IEEE Std 1366-

2003 establishes common definitions for indices used to measure electric system reliability and introduces a new reliability evaluation methodology based on the concept of "major events". Major events are defined as those instances that exceed the reasonable design and or operational limits of the electric power system. Once days are classified as normal or major event days, appropriate analysis and reporting can be done.

Q. What are the important metrics to use for analysis of electric system reliability?

A. The important indices to use in evaluating ongoing reliability of a power company's electric distribution system include the system average interruption duration index, or SAIDI; the system average interruption frequency index, or SAIFI; and the customer average interruption duration index, or CAIDI. IEEE Std 1366 provides definitions for all of these indices.

Q. How are these terms defined in IEEE Std 1366-2003?

A. SAIDI is defined as the sum of all customer interruption durations (in minutes) divided by the total number of customers served. It indicates the total duration of interruption for the average customer on the system during a predefined period of time.

SAIFI is defined as the sum of the total number of customers interrupted divided by the total number of customers served. SAIFI indicates how often the average system customer experiences a sustained interruption over a certain period of time.

CAIDI is defined as the sum of customer interruption durations divided by the total number of customers interrupted. This index represents the average time required to restore service. It is also numerically equal to SAIDI divided by SAIFI.

Q. Which index is the more important to look at in terms of assessing a power company's reliability performance?

A. Daily SAIDI is the better measure of the total cost of reliability events as compared to daily SAIFI because it can be used to express costs such as utility repair costs and customer losses. SAIFI identifies how often, on average, an interruption event occurs on the system. For most consumers, the cost of the first minute of a power interruption is no different than the cost of any succeeding minute, so keeping track of those first minutes is not as meaningful as knowing the total number of minutes. Because CAIDI is a value per customer, it does not reflect the size of an interruption event.

Q. Are these IEEE definitions the same as those currently used by PSE?

A. Not exactly. PSE defines a sustained interruption as any interruption lasting one minute or more. The IEEE defines a sustained interruption as any event that lasts more than five minutes.

Q. What is the impact of this definition difference in terms of analyzing PSE's reliability?

A. In the long run there is none. By using the shorter time duration definition for sustained interruptions, PSE accumulates more interruption events (as well as more interruption minutes) than it would using the IEEE definition. This yields a somewhat higher overall value for SAIDI. However, if you analyze the utility's year-to-year SAIDI values one against another this absolute numerical difference disappears.

Q. How is system reliability analyzed using major event days under the IEEE methodology?

A. The major event day concept is used to establish a threshold value for daily SAIDI minutes, T_{MED}. Any days with a daily SAIDI value greater than this threshold are considered as those days where the electrical system experienced above-normal stresses, such as during severe weather. The system's performance during these major event days is evaluated separately from day-to-day operation so that measurement of the underlying reliability of the electric system is not overshadowed by these significant events.

Q. How are major event days identified?

A. The major event day identification threshold value, T_{MED}, is calculated based on values of daily SAIDI for the previous five years and computed by the equation:

$$T_{MED} = e^{(\alpha + 2.5\,\beta)}$$

Where:

α = the average of the natural logarithm of each non-zero daily SAIDI value in the 5 year data set.

β = the standard deviation of the natural logarithms of the 5 year data set.

Any day that has a daily SAIDI greater than the threshold value T_{MED} that occurs during the next reporting period (typically one year ending December 31) is classified as a major event day.

Q. How does this compare to PSE's current definitions of extraordinary events?

A. PSE currently has two classifications for extreme events. A storm is defined as any weather event where five percent or more of the Company's electric customers are without power at one time. A catastrophic storm is any weather event where at least twenty-five percent of PSE's customers are without power.

Q. Why not continue to use these definitions?

A. The Company itself has said that there is a problem with the current threshold associated with the current catastrophic event definition. In her testimony starting on page 28, line 17 and continuing on pages 29 and 30, Ms. McLain states that "(t)he current definition of extraordinary storm damage is restricted by the threshold of percentage of customers without power." She concludes by noting that events that impact areas of PSE's system which do not include King County may result in significant damage, however, the Company may never reach the threshold of twenty-five percent of customers without power. Thus, such an incident would not be categorized as a catastrophic storm and the deferral accounting mechanism put in place by the Commission's Order in Docket No. UE-921262 would not be invoked.

Q. How would analysis of PSE's historical reliability and specific storm events differ using the IEEE methodology?

A. Looking at data provided by the Company in response to Staff data requests, it appears that using the IEEE methodology all of the storm events categorized by PSE as either a "storm" or "catastrophic storm" would have also been identified as a "major event day." (See Exhibit ___DEK-2). In addition, the IEEE methodology would have flagged 13 other days as major event days beyond those days PSE had identified as storm days.

Q. So would IEEE methodology work as a replacement for this catastrophic storm categorization that the Company asserts is not working adequately?

A. Yes, I believe that using the IEEE methodology to establish the major event day threshold, T_{MED}, should be the first step in any determination of whether or not to allow the Company to defer repair costs associated with an extreme event. As mentioned above, the T_{MED} threshold represents those events where the system has been stressed beyond normal operating limits. Catastrophic events where significant damage is caused and corresponding repair efforts are large also yield high daily SAIDI values.

Q. How does PSE propose to redefine the current term "catastrophic storm"?

A. PSE proposes to replace the current term with the new term "catastrophic event," which is defined to include damage to the electric and gas systems due to catastrophic natural events, such as wind storms, ice storms and earthquakes, and due to manmade disasters, such as terrorist attacks. (Exhibit No. __ (SML-1CT) at page 30, lines 12-16.)

Q. How does the IEEE major event day concept compare with PSE's proposal to replace the definition of catastrophic storm with the term "catastrophic event?"

A. Under the IEEE methodology, there is no distinction between damaging storm events and catastrophic storm events. Any day where the daily SAIDI is greater than the calculated T_{MED} threshold is categorized as a major event day. Again, the IEEE method identifies these days as those where the electric system has been stressed beyond the normal design limits. Any event that results in a large number of average customer interruption minutes fits in this category. There is no need to create separate definitions for events that are bad or really bad.

Q. What about PSE's proposal to defer all repair-related costs where the total exceeds some given dollar amount?

A. Staff witness Russell addresses at what point extreme event repair costs might be considered for deferral. He establishes a threshold based on normalized storm repair costs that would be the second condition to be met before deferral of damage repair costs would be considered. The first condition should be a daily SAIDI that is greater than the IEEE-based T_{MED}.

Q. What would be the affect on PSE's calculated annual SAIDI using the IEEE methodology?

A. Based on daily outage data provided by the Company and using the IEEE calculation methodology, from 1999 to 2003 PSE's system-wide SAIDI ranged from a high of 115 average customer interruption minutes in 1999 to a low of 99 average customer interruption minutes in 2002. Exhibit No.___(DEK-3) shows this graphically.

Q. How do these numbers compare with information reported to the Commission by PSE as part of its Service Quality Index reporting?

A. From PSE's annual reports of its Service Quality Indices (SQI) performance, as ordered in the merger under Docket Nos. UE-951270 and UE-960195, annual system-wide SAIDI ranged from a high of 142 average customer interruption minutes in 1999 to a low of 103 average customer interruption minutes the next year. Later reports show that PSE's system-wide SAIDI has been steadily increasing since 2000. The Company reported that, in 2003, its annual SAIDI was 133 average customer interruption minutes. (See Exhibit No.___(DEK-4).

Q. Since the two methods yield different values, should PSE's SQI benchmarks be revised at this time?

A. I recommend making no change to the SQI benchmarks at this time. The current SQI benchmarks were part of a settlement agreement in Docket Nos. UE-011570 and UG-011571. These benchmarks were set based on information evaluated by the parties at that time. Changing the SQI benchmarks at this time would provide no useful change in system reliability beyond any current performance incentive. However, in the future, when and if the agreement regarding the SQI benchmarks is again revised, the parties should evaluate information about the Company's reliability performance that is based on the IEEE methodology as outlined above. In addition, the SQI is a reporting tool for the Company to inform the Commission of its past performance over a given period. Properly used, the IEEE method can be an effective target developing tool for the Company to set forward-looking goals for its performance.

Q. Looking again at the chart of PSE's Company-wide SAIDI (Exhibit No.___(DEK-3), what do you conclude about its reliability performance?

A. Looking at the line representing SAIDI where major event days have been removed, one would be tempted to say that the Company's reliability performance has stayed the same or slightly improved over the period 1999 to 2003. On a system-wide, generalized basis this is actually a true statement. However, the Commission's Consumer Affairs section has received a number of complaints over the past year or so where customers were upset with the frequency and/or duration of outages on PSE's system. This indicates to me that we need to drill down further to understand real performance as seen by customers.

Q. Please explain what you mean by "drill down."

A. By drill down, I mean that you need to look at the county or circuit level in order to get a more representative idea of reliability as seen by localized customers. PSE needs to evaluate and report on smaller sections of the system in order to determine if reliability efforts are resulting in good service to customers.

Q. Why is evaluating performance at the county or circuit level important?

A. If one only evaluates reliability indices at the system-wide level, there is the potential to have areas within the system where daily SAIDI is two, three, four, or more times the system-wide average. But, because that section of the system is relatively low-density, its overall affect on Company-wide reliability indices is small. Using the system-wide value for SAIDI means only looking at an average number of interruption minutes that are divided by the total number of customers on the system. In PSE's case, this is nearly one million electric customers. The real performance is lost in the averaging.

Q. Isn't PSE required to provide an annual Electric Service Reliability Report, pursuant to WAC 480-100-398, where such information is listed?

A. Yes, WAC 480-100-398 requires all electric companies to report annually based on a reliability reporting plan established in compliance with WAC 480-100-393. PSE's report of its electric system reliability performance in 2003 was received by the Commission in March 2004. However, the Commission's reliability rule does not require companies to use IEEE Std 1366-2003 as a basis for these reports. PSE has chosen, as it is allowed to do under the rule, to report reliability indices based on its own definitions of major events. For PSE, major events are those events where more than five percent of its customers are out of service during a 24-hour period.[1]

Q. Do you recommend that PSE modify its reporting plan so as to comply with IEEE Std 1366-2003?

A. Yes. PSE should be using these industry standard definitions and calculation methodologies both internally as part of its reliability evaluation and planning, as well as to report its results to the Commission on an annual basis. This will yield a common evaluation method for use in the required annual reliability reports, in the way PSE evaluates and plans its system maintenance and expansion, and how

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[1] Puget Sound Energy Electric Reliability Monitoring and Reporting Plan, January 2002.

the Company tracks costs associated with storm repair. Finally, it makes sense for PSE to adopt this methodology since it is the only company reporting to the Commission pursuant to this rule that does not currently use it.

II. The Tree Watch Program

Q. Moving on now to the second topic area, would you please provide some background information on the vegetation mitigation program known as Tree Watch?

A. In her direct testimony, Ms. McLain indicated that PSE intended to file a petition with the Commission seeking to continue specialized accounting treatment for the Company's costs related to Tree Watch. (Exhibit No.___(SML-1CT), page 27, lines 5-8). In May 2004, the Company did file such a petition in Docket No. UE-040926 and on June 30, 2004 appeared before the Commission at an Open Meeting in support of its motion. The petition was approved by the Commission subject to a one-year time frame. During this time, costs for the continued Tree Watch program would continue to receive deferred accounting treatment. The Commission determined that deferred accounting treatment was appropriate, at least as an interim measure, until the issue was further resolved in this general rate case.

Q. What is Staff's opinion as to the merits of Tree Watch as a useful reliability enhancement tool?

A. Based on the information provided by PSE in support of its petition in Docket No. UE-040926, PSE's electric distribution system appears to be performing better under high-wind conditions associated with storms since the advent of the Tree Watch Program. PSE's information suggests that because of Tree Watch, the distribution system can now withstand higher average wind speeds than before the program started without significant damage that would result in the event being categorized as "catastrophic" (25 percent or more of customers without power).[2] This, then, represents a decrease in the amount of storm repair dollars spent on an annual basis because the system is less damaged during these storm events.

Q. Does Staff have a position on the Company's proposed level of Tree Watch spending going forward?

A. Yes. In her direct testimony, Ms. McLain proposes that PSE be authorized to spend $2 million annually on Tree Watch. (Exhibit No.___(SML-1CT), page 27, line 5). This compares to the original annual Tree Watch budget of $8 million. This proposed level of spending would compliment the ongoing vegetation management program and is in line with an ongoing program to protect the system from adverse impacts due tree damage.

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[2] Puget Sound Energy Tree Watch Program Annual Report, May 1, 2004.

Q. Is it worthwhile for PSE to extend Tree Watch to other assets, beyond the current program design that focuses only on its distribution circuits?

A. Yes. In its petition to continue the accounting treatment of the Tree Watch Program expenditures, filed in Docket No. UE-040926, PSE requested approval to modify the criteria for how program dollars would be spent. PSE stated that if it received such approval, it could target specific areas of current business and customer concerns, where off right-of-way trees are a reliability problem.[3] PSE proposed in its petition to direct approximately 75 percent of Tree Watch Program funds to transmission system enhancements during the first three years of a continued program. This would result in expenditures of $1.5 million annually for three years to improve protection of assets worth something on the order of $250 million.

Interruptions caused by outages of the transmission system can be of very long duration since much of this equipment is remote, the structures can be quite large, and deployment of highly specialized repair vehicles and equipment would likely be required. Extending Tree Watch at this level to these assets would then appear to be a cost effective strategy in terms of avoiding potentially large system-wide SAIDI impacts. Therefore, I believe that the merits of the program justify its continuation and diversification at the level and in the manner that PSE has proposed.

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[3] Petition of Puget Sound Energy, Inc. For an Order Regarding the Continuation of the Accounting Treatment of Expenditures for the Virtual Right-Of-Way Program ("Tree Watch Program"), paragraph 12, page 4.

Q. What does Staff recommend with regard to cost accounting for this program?

A. Staff's recommendations for treatment of the program's costs are included in Staff witness Russell's testimony.

Q. Does this conclude your direct testimony?

A. Yes it does.

BEFORE THE DEPARTMENT
OF PUBLIC SERVICE REGULATION
OF THE STATE OF MONTANA

In the matter of the adoption of New Rules I through VII pertaining to energy utility service standards	)	NOTICE OF ADOPTION

To: All Concerned Persons

1. On March 31, 2005, the Department of Public Service Regulation, Public Service Commission (PSC) published MAR notice number 38-2-187 regarding a public hearing on the proposed adoption of new rules I through VII concerning energy utility service standards, at page 416 of the 2005 Montana Administrative Register, issue number 6.

2. The PSC has adopted New Rules I, II, and V with the following changes, stricken matter interlined, new matter underlined:

RULE I (38.5.8601) DEFINITIONS In this subchapter the following definitions shall apply unless the context otherwise clearly demands:

(1) and (2) remain as proposed.

(3) "Major event" means a catastrophic event that:

(a) for regulated electric utilities that have adopted the Institute of Electrical and Electronic Engineers Guide for Electric Power Distribution Reliability Indices, meets the definition of "major event day," standard 1366-2003; or

(b) for regulated electric utilities that have not adopted the Institute of Electrical and Electronic Engineers Guide for Electric Power Distribution Reliability Indices:

~~(a)~~ (i) exceeds the design limits of the electric power system;

~~(b)~~ (ii) causes extensive damage to the electric power system; and

~~(c)~~ (iii) results in a simultaneous sustained electric service interruption to more than 10% of the customers in an operating area.

(4) remains as proposed.

AUTH: 69-3-103, MCA
IMP: 69-3-201, MCA

RULE II (38.5.8604) ENERGY UTILITY SERVICE INTERRUPTION NOTIFICATION (1) Each energy utility shall report promptly to ~~a local radio station and other local~~ news media that are capable of timely dissemination of information on any specific occurrence or development which interrupts or is likely to interrupt the utility's natural gas and/or electric service to ~~100~~ 500 or more of its customers for a time period longer than two hours.

AUTH: 69-3-103, MCA
IMP: 69-3-201, MCA

RULE V (38.5.8613) ELECTRIC UTILITY SYSTEM RELIABILITY

(1) The following service reliability indices measure the frequency and duration of service interruptions. They are recognized as standard reliability indices for the electric utility industry and may be applied to entire distribution systems and operating areas. For purposes of this rule, "interruption" means the loss of service for more than five minutes ~~or more~~.

(a) through (c) remain as proposed.

AUTH: 69-3-103, MCA
IMP: 69-3-201, MCA

3. The PSC has adopted New Rules III (38.5.8607), IV (38.5.8610), VI (38.5.8616), and VII (38.5.8619) exactly as proposed.

4. The following comments were received and appear with the PSC's responses:

GENERAL COMMENTS: Montana-Dakota Utilities (MDU) comments that the proposed rules will impose significant compliance costs on MDU without providing any substantive improvement in service quality. MDU comments that service standards for natural gas should be established in a separate rulemaking. Large Customer Group (LCG) supports the proposed rules, but urges the PSC also to adopt rules to recognize the specific reliability concerns of industry customers, to require utilities to take steps to identify which outages impose the largest costs and risks, and to further require prioritization to reinforcement and upgrading of facilities where service interruptions are most costly or dangerous. Montana Consumer Counsel (MCC) comments that it supported the rules. MCC urges the PSC to reject the LCG's suggestions regarding priority and cost allocation rules because to do otherwise would exceed the scope of the rulemaking notice and it would not be appropriate to establish policies regarding these controversial subjects without first having engaged in a discussion about them with interested parties.

RESPONSE: The rules will assist the PSC in meeting its responsibility to ensure energy utilities are providing adequate service. The rules should not impose significant compliance costs on energy utilities. It is an efficient use of the rulemaking process to include in these rules the provisions that apply to both electric and natural gas utilities. The PSC agrees with MCC's comments regarding the LCG comments.

COMMENTS ON RULE I: NWE recommends that the definition of "major event" at section (3) be amended to be consistent with the Institute of Electrical and Electronic Engineers (IEEE)

Standard 1366-2003, which sets the methodology for computing a "major event day."

RESPONSE: The PSC agrees with NWE's suggestion and has amended the definition to allow electric utilities that have adopted the IEEE standard for reliability reporting purposes to apply that standard while at the same time providing an alternative major event definition to be applied by electric utilities that have not adopted the IEEE standard.

COMMENTS ON RULE II: NWE recommends that notice to local media of outages should not be required until 500 customers are affected and the outage is more than two hours in duration. According to NWE, representatives in the NWE call center provide outage information to affected customers when they call to report service outages and NWE believes telephone contact is the best and most direct method of providing timely information to customers. NWE states it is able to update outage information with recorded messages that affected customers will hear when they reach the NWE call center. NWE also comments that it would be difficult to comply with the rule requirement to provide prompt notice of outages because of the wide variety of outage causes, the diverse ways NWE becomes aware of the scope and cause of outages, and the various sets of possible steps and time necessary to restore service. NWE notes that, even when NWE notifies local media of outages, there is no guarantee that the media will print or broadcast the information. NWE argues the rule would require a utility to provide two notifications to media - first to notify them of an outage and a second to notify them of service restoration. MDU suggests amending the rule to require local media notification only when 100 or more customers in an area are affected by a service interruption. MDU comments that the two-hour duration should be increased to four hours.

RESPONSE: The PSC agrees with NWE's suggestion that the threshold for number of customers affected by an outage that would trigger media notification should be increased from 100 to 500 customers. The rule has been amended accordingly. Regarding NWE's comment that it would be difficult to comply with the requirement that a utility report outages promptly to local media because it doesn't always know the scope and cause of an outage or how long it will last, the PSC responds that once a utility is aware of a service interruption that will last at least two hours and will affect 500 or more customers, then the utility may not sit on the information but instead must promptly notify media outlets that are capable of timely dissemination of the information to get the word out to customers. Utilities undoubtedly maintain their own lists of local and statewide media outlets that are able to disseminate information quickly, but examples would include the wire services and local radio and television stations. Contrary to NWE's comment that two media notifications are required by the rule, there is no expectation by the PSC or in the rule that utilities provide two notifications. Rather, the PSC expects that a utility's notification to media will contain any useful information about a significant outage, including, if known, an estimate of when service might be restored. The PSC is puzzled by MDU's comment that local media notification should be required only when 100 or more customers in an area are affected by a service interruption because that is exactly what the proposed rule requires. The PSC declines to adopt MDU's suggestion to increase the two-hour duration to four hours. Given that customers experience significant inconvenience (and possibly more serious consequences) when they lose electric or natural gas service for any length of time, a two hour outage duration is certainly a more appropriate notification threshold than four hours.

COMMENTS ON RULE IV: MDU questions the efficacy of this proposed rule because sections (1), (3), (5), and (6) are statements of general policy and, according to MDU, lack any specifically enforceable criteria. NWE recommended that section (2) be deleted because it is already industry practice to ensure utility facilities comply with the National Electrical Safety Code.

RESPONSE: The PSC disagrees with MDU's assertion that this rule is ineffective because it contains general policy statements rather than specifically enforceable criteria. The PSC believes it is important to generally describe its expectations for energy utilities. The PSC declines to adopt NWE's recommendation that section (2) be deleted as unnecessary since utilities already comply with NESC requirements. The NESC applies only to electric facilities, while section (2) is a general statement of design and maintenance expectations that applies to all regulated energy facilities, not just electric ones.

COMMENTS ON RULE V: MDU states that it follows IEEE Standard 1366 and manually monitors and analyzes its distribution and transmission system to identify system problems and avoid service disruptions. MDU suggested the rule define "distribution system" with more specificity for purposes of calculating the required indices. MDU includes in its conclusory comments a concern about the high costs that MDU would incur if it were required to implement electronic monitoring of individual circuits.

RESPONSE: The three system reliability indices that are defined in this rule are common industry-standard indices. The PSC does not believe it is necessary to define "distribution system" in this rule. The reliability indices apply to the electric utility's distribution system as a whole as well as to each of the utility's operating areas on the distribution system. In response to MDU's comment about the cost of monitoring individual circuits, section (1) does not require such monitoring.

COMMENTS ON RULE VI: MDU comments that it currently calculates manually the three indices required by this rule for its electric distribution system at the operating district level, but does not calculate these indices for its transmission system.

RESPONSE: The recordkeeping requirement in section (1) applies to service interruptions on the distribution system and to each operating area on the distribution system. There is no requirement to calculate the reliability indices for the transmission system.

COMMENTS ON RULE VII: MDU comments that this rule would require MDU to incur implementation costs because MDU does not have the equipment or measuring systems in place to measure and collect data as required by the rule. MDU specifically mentions that it does not include major storm events in its calculations and does not capture the indices down to the circuit level. MDU adds that it does not believe implementation of this rule would do anything to improve customers' service quality.

RESPONSE: MDU indicates in its comments that it does calculate CAIDI, SAIDI and SAIFI indices at the present time. The rule does not require calculation of the indices down to the circuit level. The requirement to calculate the indices with and without major events included ensures that the PSC is able to take into account the effect of major events on the indices when reviewing the reliability reports. The annual reliability report will assist the PSC's efforts to monitor the adequacy of service provided by regulated electric utilities.

Greg Jergeson
Greg Jergeson, Chairman

Robin A. McHugh
Reviewed by Robin A. McHugh

Certified to the Secretary of State on July 18, 2005.